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OIL PRODUCTION IN THE ARCTIC NATIONAL WILDLIFE REFUGE

The Technology & the Alaskan Oil Context

CONGRESS OF THE UNITED STATES OFFICE OF TECHNOLOGY ASSESSMENT

J952-8

Recommended Citation:

U.S. Congress, Office of Technology Assessment, *Oil Production in the Arctic National Wildlife Refuge: The Technology and the Alaskan Oil Context*, OTA-E-394 (Washington, DC: U.S. Government Printing Office, February 1989).

Library of Congress Card Catalog Number 88-600565

For sale by the Superintendent of Documents U.S. Government Printing Office,
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Foreword

This OTA assessment responds to requests from the House Committee on Merchant Marine and Fisheries and the Senate Committee on Energy and Natural Resources for an examination of some technical issues concerning the potential future development of oil resources within the coastal plain of the Arctic National Wildlife Refuge (ANWR) in northeastern Alaska. Because geologists suspected that large quantities of oil might lie beneath the coastal plain, Congress had earlier exempted the plain from a Federal Wilderness designation given to about 8 million acres within ANWR. The U.S. Department of Interior has released a "legislative environmental impact statement" recommending the immediate leasing of the entire coastal plain for oil exploration and development. Upon release of that report, the plain's future became the focus of a high-stakes debate among a variety of environmental, business, Alaskan native, and government groups with greatly conflicting views of the appropriate balance of commercial, environmental, and other values of the plain. Differing hopes for the plain's future have emerged, ranging from full-scale oil development to wilderness designation and protection from man-caused change.

In deciding the future of the ANWR coastal plain, Congress must address a wide variety of issues ranging from the environmental impacts of oilfield exploration, development, and production in an Arctic environment to the economic and national security benefits of potential additional oil production in Alaska. These issues have been explored in a wide-ranging series of congressional hearings sponsored by four House and Senate committees, reports issued by business and environmental groups, executive branch reports, and a series of studies conducted by the Congressional Research Service and the General Accounting Office.

This report presents the results of an assessment of a subset of these issues focusing in particular on: the oilfield technology being used to develop the Alaskan North Slope's oil resources and the likely configuration of that technology as it might be applied in the future to the coastal plain; and the prospects for future North Slope oil production, especially the likelihood that the flow of oil through the Trans Alaskan Pipeline System will suffer a serious decline during the next decade.

A forthcoming OTA assessment, scheduled for release in the fall of 1989, will assist Congress in addressing a third issue--ANWR's potential role in future U.S. liquid fuel supplies. The assessment (entitled Technological Risks and Opportunities for Future U.S. Energy Supply and Demand) will examine, among other subjects, trends in future U.S. oil production and use, and the potential to reduce oil use by substituting alternative fuels and improving energy efficiency.

OTA is indebted to the numerous individuals who contributed substantial time to this report, providing information and advice and reviewing drafts.

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Many other individuals reviewed and made comments on sections of the report. In particular, OTA wishes to thank Carl Behrens, Congressional Research Service, David Campbell, National Wildlife Federation, Paul Deissler, Houston, Texas, E. Kaarlela, Bureau of Land Management, Lawrence Kumins, Congressional Research Service, Helmut Merklein, Energy Information Administration, James Mielke, Congressional Research Service, John Moore, Congressional Research Service, John Pearson, Energy Information Administration, Joseph Riva, Congressional Research Service, Milton Russell, University of Tennessee, William Sackinger, University of Alaska, Fred Sissine, Congressional Research Service, Arlon Tussing, ARTA, Inc., Seattle, Washington, Michael Utt, Unocal Corporation, and David Watts, Office of the Solicitor, U.S. Department of the Interior.

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Summary and Conclusions

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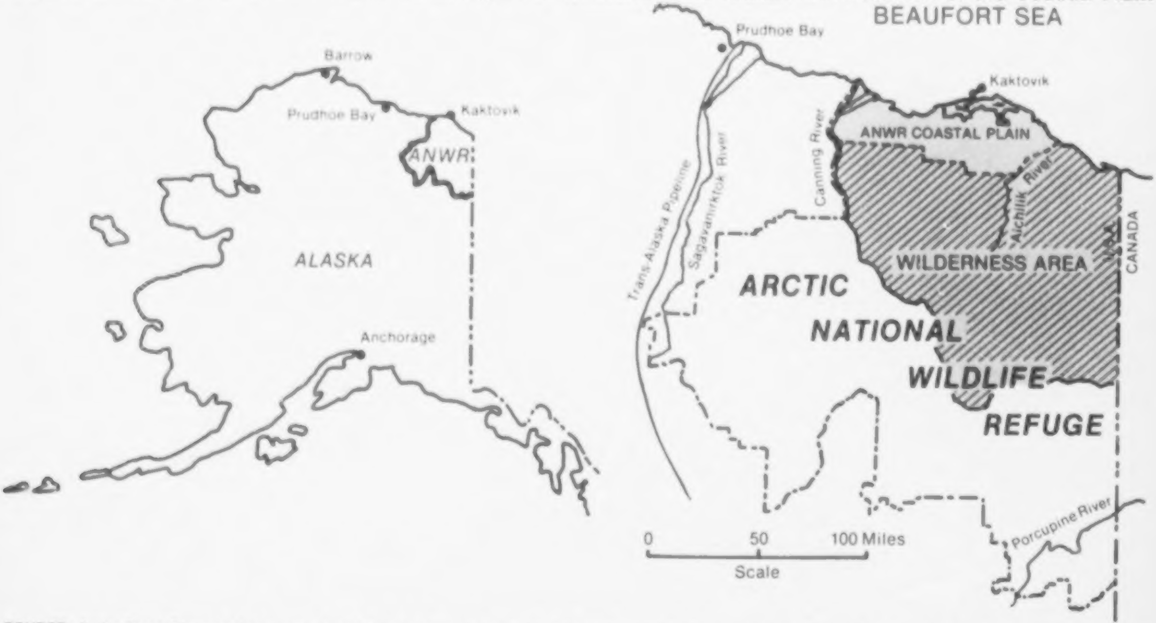
Summary and Conclusions

INTRODUCTION

The coastal plain of the Arctic National Wildlife Refuge (ANWR), in the extreme northeast corner of Alaska (see Figure 1), has become the focal point of a major debate among interest groups seeking either to promote or to block the leasing, exploration, and development of the area for its suspected massive oil resources (see Box A). Those groups opposing the development of ANWR oil resources view the coastal plain as a unique and invaluable Arctic ecosystem and wilderness area. They fear that development will destroy the plain's wilderness character and seriously damage its wildlife and other environmental values in return for a small potential to capture an amount of oil that will make only a temporary dent in the United States' liquid fuels dilemma. They believe that previous North Slope development has damaged the Arctic environment and serves as a warning against expansion of development into the coastal plain.

Pro-development interests view the coastal plain as the most promising remaining area in the United States for finding supergiant oilfields, and they believe that the oil industry can explore and develop the area without significantly compromising its environmental values. In contrast to the views expressed by the environmental groups opposing ANWR development, those favoring ANWR development characterize existing North Slope oil development as a convincing example of sound environmental management

Figure 1.—The Arctic National Wildlife Refuge: Its Relationship to Alaska and Location of the Coastal Plain


BEAUFORT SEA
Barrow
Prudhoe Bay
Kaktovik
ANWR
ALASKA
Anchorage
Prudhoe Bay
Kaktovik
ANWR COASTAL PLAIN
Trans-Alaska Pipeline
Sagavanirktok River
Canning River
Aichilik River
WILDERNESS AREA
CANADA
ARCTIC
NATIONAL
WILDLIFE
REFUGE
Porcupine River
0
50
100 Miles
Scale

SOURCE: Arctic Slope Regional Corp., "The Arctic National Wildlife Refuge. Its People, Wildlife Resources, and Oil and Gas Potential," revised May 1987.

BOX A
THE COASTAL PLAIN OF THE ARCTIC NATIONAL WILDLIFE REFUGE

- Comprises 1.5 million acres of the 19-million-acre Arctic National Wildlife Refuge, established by the Alaska National Interest Lands Conservation Act of 1980 (ANILCA). Known as the "1002 area," a reference to Section 1002(b) of ANILCA, defining the coastal plain
- Located in the extreme northeast corner of Alaska; western edge 60 miles east of Prudhoe Bay, the Nation's largest oilfield; eastern edge 160 miles east of Prudhoe Bay and 30 miles west of the Canadian border
- Climate characterized by long, extremely cold winters and short, cool summers; persistent winds throughout the year; frequent blizzards in winter; precipitation light but frequent
- Not included in the 8 million acres of ANWR designated as wilderness in 1980, but set aside by Congress for additional study by the Department of the Interior of oil and gas potential and of wildlife resources of the area
- Leasing or other activities leading to oil and gas production must be authorized by the U.S. Congress
- The Department of the Interior released its report in April 1987, recommending orderly oil and gas leasing of the area
- Knowledge of subsurface geology very limited, but located between known petroleum provinces in the United States and Canada, and the petroleum-bearing strata of both may be present in the refuge
- Considered by the oil industry to be the most promising unexplored area in the United States for discovering supergiant oilfields
- The Department of the Interior estimates there is a 19 percent chance of finding economically recoverable oil; if any recoverable oil is found, there is likely to be a mean of 3.23 billion barrels.
- Considered by environmentalists to have outstanding wilderness values and to be an especially important habitat for caribou, polar bears, musk oxen, and migrating birds
- The area is a prime calving ground for the approximately 200,000 caribou of the Porcupine caribou herd, which is present on the coastal plain from about mid-May to mid-July

Photo credit: Arctic Slope Consulting Engineers

Winter on the coastal plain of the Arctic National Wildlife Refuge.

and proof that the Nation can obtain oil from the ANWR coastal plain without unduly disturbing its environmental values.

Through the terms of the legislation that established the Refuge, Congress has the final decision over whether the coastal plain can be leased for oil development. The ongoing congressional debate over the coastal plain's future has been informed by extensive hearing testimony as well as by a variety of analytical reports from executive and congressional branch agencies, industry, academia, and environmental organizations. Much of the testimony and reporting has focused on the potential environmental impacts that development would cause and the nature of the environmental "record" of previous oil development on the Alaskan North Slope.[1]

In this report, the Office of Technology Assessment (OTA) has not attempted to duplicate this information or to produce a complete assessment of all of the issues involved in Congress' decision about ANWR's future. In particular, **we have not produced an environmental assessment of ANWR oil development.** Instead, at the request of the Senate Committee on Energy and Natural Resources, the House Committee on Merchant Marine and Fisheries, and the OTA Technology Assessment Board, we have focused on two issues that will form a part of the congressional decision:

1. **The nature of ANWR oilfield technology.** To what extent would ANWR development look like existing development on the North Slope? Would the basic technologies and practices be the same or different?
2. **ANWR's potential role in Alaskan oil production.** How credible are recent projections of large declines in North Slope oil production in the 1990s?

---

[1] Opposing views of the environmental record are presented in: "Oil in the Arctic: The Environmental Record of Oil Development on Alaska's North Slope," Natural Resources Defense Council, Inc., January 1988; and "Current ANWR Environmental Issues," The Standard Oil Co., August 1987.

ARCTIC OILFIELD DEVELOPMENT AND TECHNOLOGY

Overview

The technology and practices of Arctic oilfield exploration and development have undergone important changes in the years since the Prudhoe Bay oilfield was discovered and development began (see Box B for a brief description of the process of extracting oil and gas resources). Some important examples of technological changes include improved drilling rig design and operation, improved use of directional drilling (drilling at an angle off the vertical) to allow multiple wells on single gravel "pads" to drain oil from a greater area of the field; improved analytical techniques to design against well damage from permafrost thawing, allowing closer well spacing and thus smaller gravel pads and less coverage of the tundra; and improvements in the use of enhanced oil recovery technologies. These changes in technology and practices stemmed from three sources:

1. the pressure of designing to solve unique Arctic problems and adapting to the harsh Arctic environment,
2. the industry-wide technological changes stemming from the constant drive to improve capabilities and performance and reduce

BOX B
THE OIL PRODUCTION CYCLE

The extraction of oil resources is commonly divided into three phases: (1) Exploration, (2) Development, and (3) Production. Exploration includes seismic (acoustic) and other surveys to map the possible underground petroleum reservoirs as well as drilling exploratory wells to confirm the existence and location of an actual oil pool (the pool, or reservoir, is actually a mass of porous rock, with the oil stored in the rock pores). If oil is found,[1] further drilling is also necessary to delineate the size and extent of a reservoir and to determine whether it can be economically produced. Exploration is completed when a decision is made to produce an oilfield or pool. Development is the process of building and installing all of the facilities, machinery and pipelines needed to produce whatever oil is discovered. On the North Slope, development begins with building airfields, roads, drilling pads, and construction camps. This is followed by drilling production wells; building modules containing machinery and processing plants and installing them on the site; building and installing pipelines and flow control equipment; and installing a myriad of machinery to support a complex network through which oil flows from a pool deep beneath the ground to the surface, is processed to yield crude oil and is pumped long distances to terminals for loading on tankers. Production begins when all development is completed and the facilities begin producing oil for the market. The production phase also includes maintenance of the facilities and the wells, drilling more wells to keep oil flowing and to keep the underground reservoirs operating smoothly, and installing special equipment for "enhanced oil recovery" to extract the oil left behind by the conventional production wells.

When the oilfields are large, as they are on the North Slope of Alaska: the machinery and facilities are large and extensive; thousands of people are involved in both development and production; the development resembles a major industrial complex; and the process spans at least a few decades.

---

[1] Or gas is found. Often, reservoirs contain both oil and gas, with the gas both in solution in the oil and in a separate "gas cap." On the North Slope, most of the produced gas is reinjected into the reservoir, both to maintain reservoir pressure (which helps the oil to flow) and to avoid having to dispose of the gas by flaring—at current prices, it is not economical to ship the gas to markets.

costs, as well as from fortuitous scientific advances in other industries (such as electronics), and

3. the special urgency to improve efficiency and reduce costs associated with the decline in oil prices beginning in 1981, especially the large price drop initiated in December 1985.[2]

OTA believes that the rate of change in Arctic technology and practices likely to be used for ANWR oil development may be more gradual in the future, primarily because some of the pressure for change has lessened. In particular, industry knowledge of how to operate efficiently in the onshore Arctic environment has matured considerably, and further advancement in knowledge should slow from its previous pace. In addition, basic physical conditions on the ANWR coastal plain, while not identical to the current North Slope development area, are quite similar and do not represent a new challenge to industry technology per se. Unless economic or regulatory conditions change, the industry is more likely to deploy systems that have been tried and tested under similar conditions than to take substantial risks in the development of new technologies. Therefore, we conclude that, **in the absence of new pressures, ANWR oilfield technology and practices will most likely resemble the technology and practices used at Kuparuk and Endicott, the latest North Slope fields, modified to fit the particular field characteristics encountered.**

Of course, the constant incentive to lower costs will continue to drive innovation in the industry, and Arctic technology will continue to evolve. Promising areas for technological change include directional drilling, where advances continue to be made in offshore developments such as the North Sea, and enhanced oil recovery, where innovation will be driven by industry desire to boost the economic potential of fields throughout the United States and, on the North Slope, in fields such as West Sak. Also, an additional motivation for technological change could come from new regulatory pressures. For ANWR oil exploration and development, this pressure could arise from dissatisfaction with current environmental performance at Prudhoe Bay and the other developed North Slope fields, or because the State and Federal authorities seek a higher standard of environmental protection at ANWR because of its status as a wildlife refuge. If this type of pressure arises, the most likely focus for changes in technology and practices would be in the area of waste management and habitat protection.

Conclusions[3]

1. **The major differences between North Slope and Lower 48 conditions that affect the choice and use of oilfield technologies are the very cold weather, the presence of permafrost (ground which is permanently frozen except at the surface, which thaws during the Arctic summer), and the remoteness of the area.** Designs for technologies for operating at sub-zero temperatures draw heavily on advanced concepts in metallurgy, elastomers (elastic substances), lubricants, and fuels. The harsh and extremely cold environment also has demanded development of new survival systems and procedures to assure personnel safety. All drilling rigs and production facilities where people work are enclosed, insulated, and heated. Exterior steel structures are built from a special arctic-grade steel to prevent brittleness at very low temperatures. Most pipelines and flowlines are insulated, either to prevent water from freezing, to avoid increased viscosity of the crude oil, or to avoid permafrost melting. Shut-in flowlines are freeze-protected or evacuated and then filled with inert gas.

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[2] See U.S. Office of Technology Assessment, U.S. Oil Production: The Effect of Low Oil Prices - Special Report, OTA-E-348, (Washington, DC: U.S. Government Printing Office, August 1987).

[3] In evaluating Arctic technology, OTA had to rely primarily on industry sources of data; there are few truly "independent" analysts with extensive knowledge of Arctic oilfield technology and production, and analysts in the Alaskan State agencies and Federal agencies such as the Minerals Management Service are also dependent on industry as their primary information source. This comment applies, as well, to our analysis of future North Slope oil production.

Photo credit: Arctic Slope Consulting Engineers

Production well pad with drilling rig at Prudhoe Bay.

To prevent the permafrost from melting and to provide a stable surface during the summer thaw, roads, buildings, pipelines, drilling pads, etc. are built atop thick gravel pads and/or elevated on supports. And because the harshness and remoteness of the North Slope make normal on-site construction methods difficult and expensive, major facilities are built in huge modules in the Lower 48 States, barged to the slope, and installed on prepared foundations.

2. **Although the technologies and practices used on the North Slope today have evolved considerably from those of the early '70s during the beginning of Prudhoe Bay development, the majority of changes have involved the adaptation of available practices and technologies to a new environment rather than the development of new technologies and practices.** The adaptations address the unique Arctic environment, as described above. Although this conclusion does not negate the importance of what the oil industry has achieved in Alaska – it has made tremendous strides – it is important in projecting future technological development, because it implies that future changes may come more slowly.

3. Most of Prudhoe Bay and the Trans Alaska Pipeline System (TAPS) have been in routine operation for some time. **The industry now believes that it has ascended most of the way up the "Arctic learning curve," that its technologies and practices for Arctic development are mature, efficient, and effective. Therefore, they see little need to change them for ANWR except to modify them to fit specific conditions found on the coastal plain (for example, the size, shape, depth, and location of any oil-bearing reservoirs discovered), and many in the industry foresee little likelihood that the technologies and practices will change significantly for ANWR development.**

4. **Although the ANWR physical environment is not precisely the same as that of Prudhoe Bay and the surrounding area, the differences do not appear to be large.** ANWR has more topographic relief than Prudhoe Bay, producing less standing water but more potential problems with channeling and erosion; there are fewer deep lakes there to serve as sources of fresh water; gravel conditions are about the same; and ANWR contains a few more port sites with deeper water near shore. None of the differences appear to challenge industry capabilities per se.

5. **At least a portion of the environmental effects associated with existing North Slope oil development should not automatically apply to ANWR. The capability now exists for reducing or eliminating some of the impacts reported for early Prudhoe Bay development. Newer North Slope fields such as Kuparuk and Endicott incorporate improvements in environmental management such as reduced requirements for surface usage and gravel, improved handling of oilfield service operations, and more attention to waste management.** These and other improvements are also likely to be used in any ANWR development and, if necessary, regulatory agencies could stipulate use of desirable practices as a condition of development. **Critics, however, have expressed continued serious concerns about several environmental issues because they believe that even the newest operations are still causing significant environmental damage.** Their principal concerns include disposal of reserve pit waste and of other solid and liquid wastes, air pollution, fresh water supply, monitoring of industry activities by resource agencies, and wildlife habitat alteration or destruction. Also, many groups argue that the environment of the ANWR coastal plain deserves greater protection than Prudhoe Bay because the coastal plain is part of a wildlife refuge. **These groups either oppose development outright or conclude that oilfield technologies and practices must change significantly from those used for current North Slope development if environmental values are to be protected properly.** OTA has not evaluated these issues in this report.

6. **If ANWR is leased and commercial quantities of oil are discovered, the period of development and production is not likely to be brief.** Examination of the development cycle of oil regions in the Lower 48 and around Prudhoe Bay shows that the life

Photo credit: Standard Alaska

The Arctic National Wildlife Refuge Coastal Plain. The terrain is rolling, whereas Prudhoe Bay to the west is quite flat.

cycles of such regions are long and complex. Development of ANWR is likely to begin with exploration and development of large oilfields. With the development of an extensive infrastructure, however, further development will become economic, and exploration will focus on smaller fields. Also, opportunities for enhanced oil recovery, for the development of fringe areas of the large reservoirs, and for development of smaller reservoirs will extend high activity levels at the larger fields. In the long term, gas resources may be developed. This scenario implies an extensive and elaborate infrastructure, and thus a significant visual impact, coverage of the surface, and accompanying ecosystem impacts for at least 25 to 30 years. Although the industry argues--correctly--that actual coverage of the surface is likely to be less than 1 percent of the coastal plain, the physical coverage would be spread out somewhat like a spiderweb, and some further physical effects, like infiltration of road dust and changes in drainage patterns, will spread out from the land actually covered.

7. The detailed form of any future ANWR oilfield development cannot be predicted. Nevertheless, it is useful to postulate **a hypothetical scenario for the ANWR coastal plain:**

- Two fields would be discovered and developed:
  - one large: 3.0 billion barrels of oil recoverable
  - one small: 0.5 billion barrels of oil recoverable
- The large field is one-third the size of the Prudhoe Bay oilfield, and the small field roughly the size of the Endicott oilfield.
- Production from these two ANWR oilfields would total 800,000 bbl/day - or 40 percent of current North Slope oil production.
- Facilities for two ANWR oilfields would include:
  - 800 wells on 14 gravel pads;
  - 3 major and 4 satellite production facilities; and
  - 2 airfields, 2 ports, 2 seawater treatment plants, and one industrial support center.
- Total gravel coverage including pads, roads, etc. is 3,000 to 4,000 acres.
- Total "footprint" – including pipelines and other disturbances – is 5,000 to 7,000 acres.
- Total "sphere of influence" – denoting area where some secondary effects occur on certain sensitive species – is 150,000 to 300,000 acres.
- Hypothetical schedule:
  - Exploration - 1991 to 1999
  - Development - 1996 to 2006
  - Production - 2002 to 2030

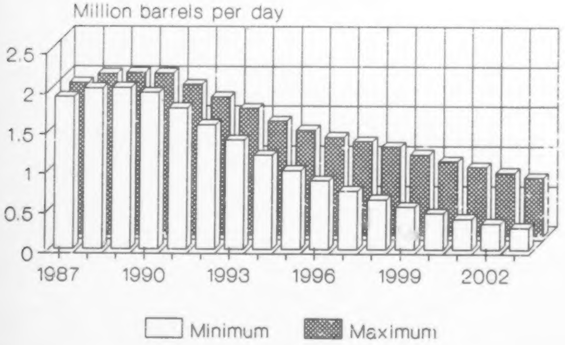
NORTH SLOPE OIL PRODUCTION

Overview

Today, the North Slope of Alaska provides about 2 million barrels per day (mmbd) of oil to the United States, nearly a quarter of total U.S. domestic crude oil production. Most projections of future North Slope production show a marked decline beginning around 1990 to 1991, with production falling to half of current levels or below by the year 2000 (see Figure 2). If production is not to fall, then it must come either from more intensive development of existing fields, from discovered but undeveloped fields, or from undiscovered resources. **Based on the available evidence, additional production from more intensive development of existing fields and development of discovered but currently undeveloped fields is unlikely to reverse the expected decline in North Slope oil production. Production from undiscovered resources is highly uncertain and would likely be more than a decade away even if discoveries were made this year.**

OTA notes, however, that the Prudhoe Bay operators have been able to push back the expected date for the onset of field decline several times. Although it is not clear how a strong production decline can be delayed for much longer, history suggests caution in entirely writing off the possibility.

Figure 2.-Projected TAPS Throughput



SOURCE: Alaska Department of Natural Resources, Division of Oil and Gas.

Conclusions

1. The current low oil prices raise the possibility that the oil companies on the North Slope might be foregoing opportunities for adding large increments of production and/or added recovery, waiting for economic conditions to improve. If this were true, then existing forecasts of future North Slope production might be missing the production boost that an improvement in economic conditions could bring about.

   Although low oil prices have affected the level of investment in new development on the North Slope, in general the large producing fields continue to be developed intensively. Despite the low prices, we could not identify any development opportunities being foregone that would make a large difference in future North Slope production. Thus, **higher oil prices may slow but are unlikely to stop the expected declines in North Slope oil production.**

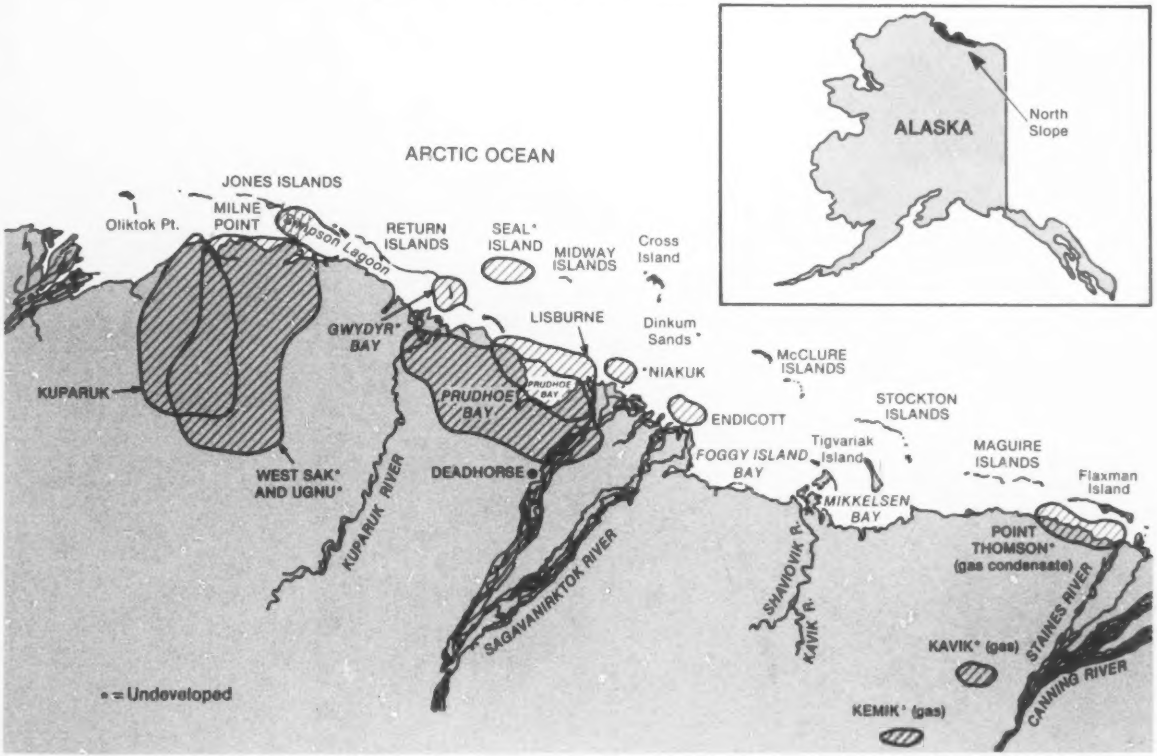
2. Prospects for enhanced oil recovery (beyond that already in place or scheduled) in the discovered fields are good, but the increments of recovery and production from the available enhanced oil recovery (EOR) technologies will be small and will accrue over a long period. In other words, **there are no available or readily foreseeable technologies that promise to "turn around" expectations of declining production at Prudhoe Bay and other North Slope fields.** Table 1 describes the conditions affecting oil recovery in the discovered North Slope fields; Figure 3 shows the location of these fields.

3. Aside from additional recovery from the producing fields, increments of production must come from discovered but non-producing fields or from the undiscovered resource base.

Photo credit: American Petroleum Institute

A quarter of the United States' domestic production of crude oil flows through the Trans Alaska Pipeline System (TAPS).

Figure 3.—North Slope Oilfields


ALASKA
North Slope
ARCTIC OCEAN
JONES ISLANDS
Oliktok Pt.
MILNE POINT
Simpson Lagoon
RETURN ISLANDS
SEAL* ISLAND
MIDWAY ISLANDS
Cross Island
LISBURNE
Dinkum Sands*
GWYDYR* BAY
*NIAKUK
McCLURE ISLANDS
STOCKTON ISLANDS
KUPARUK
PRUDHOE BAY
PRUDHOE BAY
ENDICOTT
Tigvariak Island
FOGGY ISLAND BAY
MAGUIRE ISLANDS
Flaxman Island
WEST SAK* AND UGNU*
DEADHORSE
MIKKELSEN BAY
POINT THOMSON* (gas condensate)
KUPARUK RIVER
SAGAVANIRKTOK RIVER
SHAVIOVIK R.
KAVIK R.
STAINES RIVER
KAVIK* (gas)
CANNING RIVER
KEMIK* (gas)
* = Undeveloped

SOURCE: Office of Technology Assessment, 1988.

a. **The discovered but non-producing fields do not have large volumes of recoverable resources** and cannot be expected to reverse the impending decline in oil flow through the Trans Alaska Pipeline System (TAPS).

b. Although the **West Sak field** contains large in-place resources (at least 15 billion barrels), there are, as yet, no available technologies that can economically recover more than a small fraction of these resources. ARCO, the majority owner of this field, plans to begin a pilot drilling program soon, and hopes eventually to produce a few hundred thousand barrels per day from West Sak. Given the substantial technical problems remaining, however, large scale oil production from West Sak must be viewed as highly uncertain.

c. As for the undiscovered resources, recent exploration on the North Slope and offshore has been extremely disappointing. **Although new large discoveries cannot be ruled out, the prospects for such discoveries seem to have dimmed considerably.**

4. The industry appears to have made significant strides in controlling and reducing oilfield costs over the past few years. Part of the reduced costs are associated with reduced prices for basic oilfield services, and these lower prices are unlikely to be sustained for more than a few years. Part, however, appears to be the result of improved practices and design, and this should be sustained permanently. The industry now appears to be able to bring new fields on line and develop older fields more intensively at lower breakeven oil prices than just a few years ago. To the extent that production projections are

Table 1.—Summary Field Data

Field	Remaining recoverable oil-1/88	Estimated recoverable gas-1/88	Recovery factor	Daily oil production	Present EOR	Factors limiting production
Prudhoe Bay	4,100-6,000 million barrels	23 trillion cubic feet	42-45% of original in-place resources	1,550,000 barrels per day	Waterflood; miscible gas injection; infill and horizontal drilling	Although a good performer, production will ultimately be limited by residual oil saturation to waterflood
Kuparuk	600-1,100 million barrels	600 billion cubic feet	Approximately 30% of original in-place resources	300,000 barrels per day	Waterflood; miscible gas injection	Faulting, thin pay, and residual oil saturation waterflood
Lisburne	280-580 million barrels	900 billion cubic feet	7-22% of original in-place resources	50,000 barrels per day	Small waterflood pilot is being tested	Difficulty of producing fractured limestone reservoir; low porosity and permeability
Endicott	270-445 million barrels	800 billion cubic feet	35% of original in-place resources	100,000 barrels per day	Waterflood	Faulting; gas handling ability in future
Milne Point	0-95 million barrels	None	Approximately 33% of original in-place resources	N/A; currently shut-in due to low price of oil	Waterflooding	Extensive faulting
West Sak	0-1,200 million barrels	None	0-5% of original in-place resources	N/A	Test only of heated waterflood	Poor (shaly) rock; unconsolidated, fine-grained sand; viscous, low temperature oil
Seal Island	0-300 million barrels	?	Approximately 33%	N/A	N/A	?
Niakuk	55-75 million barrels	?	Approximately 33%	N/A	N/A	?
Point Thomson	350 million barrels condensate (light gravity hydrocarbons)	5 trillion cubic feet	?	N/A	N/A	?

SOURCE: Office of Technology Assessment, 1988.

based on older costs, they may be pessimistic. Also, because reserve projections and production rates are oil price dependent, higher oil prices in the mid to late 1990s could be expected to stimulate additional production. Thus, **the more optimistic of the current projections for North Slope production over the next 15 to 20 years are more likely to be accurate, especially if higher oil prices prevail. However, even the optimistic projections still foresee a large decline in the flow of oil through TAPS during the next decade and a half.**

5. The oil industry has over time tended to be overly pessimistic about prospects for future oil production, not only in Alaska but for the United States as a whole. Projections for the onset of decline in Prudhoe Bay production, for example, have been pushed back a number of times. And U.S. production, although down substantially since the oil price drop of 1985-1986, has not fallen nearly as severely as the industry had predicted immediately following the price drop. Although OTA could not identify a likely means to maintain North Slope production at levels much higher than the "high" curve in Figure 2, OTA is reluctant to totally rule out this possibility.

6. Estimates of the resource potential of ANWR are highly speculative, given that they are not based on extensive drilling data. DOI's "best guess" of ANWR's economically recoverable resources is based on available geologic and geophysical data and on a number of economic assumptions. Several factors lead OTA to conclude that **DOI's estimate of the likelihood of finding economically recoverable quantities of oil in ANWR may be conservative.** These factors are: 1) In its analysis, DOI assumed that the costs to develop ANWR will be similar to costs as detailed in the 1981 National Petroleum Council report on the Arctic. The oil companies have reduced their costs substantially since 1981, and these reductions do not appear to have been captured by the DOI assessment;[4] 2) DOI did not include the possibility that ANWR oil could be developed with two or three moderate-sized fields, even though no single field exceeds the minimum economic field size for a stand-alone field; and 3) Smaller potential oil prospects were not included in DOI's analysis. Even though these smaller prospects are not large enough to develop alone, some would likely be developed in association with a large prospect.

7. Many groups have either misinterpreted or misused DOI's estimate of ANWR's economically recoverable resource potential. What DOI has concluded is that there is an 81 percent chance that no economically recoverable oil will be found in ANWR, but if ANWR contains any recoverable oil, a mean of 3.23 billion barrels is likely to exist. Estimates will change with acquisition of additional data, but geologic conditions for finding oil in ANWR are favorable, and industry considers a 19 percent probability of finding economically recoverable oil in any region to be good odds.

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[4] Although some of the cost reduction may not be permanent, OTA believes that much of the savings will be retained even if drilling activity levels pick up.

Chapter 1

Introduction

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Introduction

OVERVIEW

The coastal plain of the Arctic National Wildlife Refuge, in the extreme northeast corner of Alaska (see Figure 1-1), has become the focal point of a major debate among interest groups seeking either to promote or to block the leasing, exploration, and development of the area for its suspected massive oil resources. Because of the perceived oil and gas potential of the area, the 1.5 million acre coastal plain, or so-called "1002 area" named after Section 1002 of the Alaska Native Interest Lands Conservation Act (Public Law 96-487), was left out of the Federal wilderness designation that protected 8 million acres in the Refuge. Instead, Congress asked the Department of the Interior (DOI) to study the area and to recommend an appropriate development course for it. Oil and gas development was forbidden without explicit congressional approval. DOI has now completed its study and has recommended to Congress that the entire 1002 area be opened to leasing and development.[1] This recommendation is fully supported by the oil industry and a variety of other pro-development interests (including the entire Alaskan congressional delegation), is vigorously opposed by a number of environmental groups and some Native groups, and is supported *with conditions* by the Alaskan State government and other interests. The variety of proposed Federal legislation dealing with the Refuge—summarized in Box 1-A—reflects these different positions.

The 1002 area is the focus of a variety of seemingly conflicting values. On one side, there is unanimous agreement that the area represents a high value as a wildlife refuge—the 1002 coastal plain is, in most years, the primary calving ground and summer home for the nearly 200,000 caribou of the Porcupine herd, as well as the nesting habitat for millions of birds and the home of polar and grizzly bears, an expanding herd of musk oxen, and numerous other arctic species. Also, there is widespread agreement—supported even by the DOI report that recommended its development—that it has a high value as a wilderness area. Further, the area provides wildlife resources—particularly caribou—supporting the subsistence lifestyle of a number of native Inuit. On the other side, there is essentially unanimous agreement that the 1002 area has a high potential—by industry standards—for containing massive oil and gas deposits, although various interest groups differ on the value of these deposits to the Nation (see Box 1-B).

It seems unlikely that all of these values can be supported simultaneously. For example, according to the DOI report, the successful exploration for and development of the 1002 area's potential oil resources would damage and possibly destroy the area's wilderness character. Although some interests have argued that the wilderness character can be restored over time, at our current state of knowledge this outcome should be viewed as extremely uncertain, and probably unlikely. Thus, the true "value" of the coastal plain as a wilderness area, though largely a subjective measure, is an important part of the development decision.

In addition, there is substantial disagreement about the potential conflict between large-scale oil development and the wildlife and other environmental and subsistence values of the area. Generally, the oil companies vigorously defend their environmental record in previous Alaskan North Slope development and assert that ANWR oil can be extracted with little damage to wildlife and other values. Environmental groups are taking the opposite view that previous development has caused substantial damage and that any future oil development in ANWR also will substantially damage wildlife and other environmental values.

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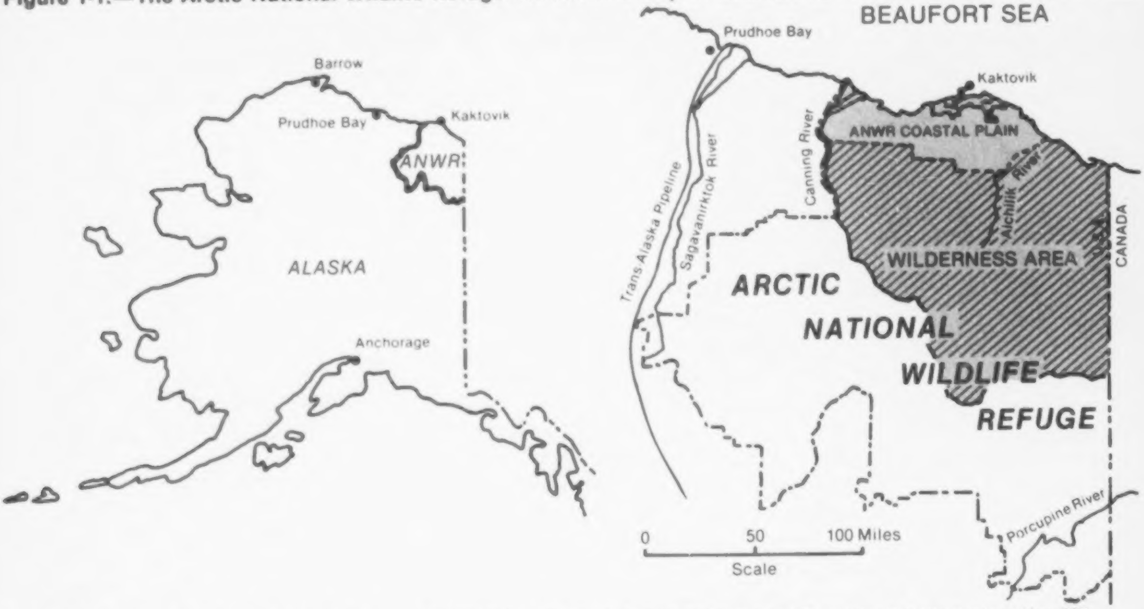
[1] N.K. Clough, R.C. Patton, and A.C. Christiansen (eds.), Arctic National Wildlife Refuge, Alaska, Coastal Plain Resource Assessment—Report and Recommendation to the Congress of the United States and Final Legislative Environmental Impact Statement, (Washington, DC: U.S. Fish and Wildlife Service, U.S. Geological Survey, and Bureau of Land Management, U.S. Department of the Interior, 1987).

These conflicting viewpoints have been the subject of a number of congressional hearings as well as studies by a number of groups. The issues raised during the hearings are summarized in Box 1-C.

Figure 1-1.—The Arctic National Wildlife Refuge: Its Relationship to Alaska and Location of the Coastal Plain


Barrow
Prudhoe Bay
Kaktovik
ANWR
ALASKA
Anchorage
BEAUFORT SEA
Prudhoe Bay
Kaktovik
ANWR COASTAL PLAIN
Canning River
Trans Alaska Pipeline
Sagavanirktok River
Aichilik River
WILDERNESS AREA
U.S.A.
CANADA
ARCTIC
NATIONAL
WILDLIFE
REFUGE
Porcupine River
0
50
100 Miles
Scale

SOURCE: Arctic Slope Regional Corp., "The Arctic National Wildlife Refuge. Its People, Wildlife Resources, and Oil and Gas Potential," revised May 1987.

Photo credit: American Petroleum Institute

The site of Chevron's KIC well, which is the only onshore exploratory well to probe ANWR's oil potential. The well was drilled from a temporary insulated pad, and the site is now being rehabilitated. The success of this rehabilitation effort will clarify arguments over the long-term impacts of exploratory drilling in ANWR.

BOX 1-A
ARCTIC NATIONAL WILDLIFE REFUGE BILLS

More than a dozen bills have been introduced in the 100th Congress that address issues related to the Arctic National Wildlife Refuge. Two pro-leasing bills, S 2214 and HR 3928, have emerged as the leading bills around which debate is currently centered.

S 2214, which incorporates some of the provisions of a pro-leasing bill introduced by Senators Murkowski and Stevens of Alaska, was reported by the Senate Energy and Natural Resources Committee on February 25, 1988. The bill provides for a phased-in leasing program governed by existing State and Federal environmental law, and subject to further environmental regulations to be developed by the Interior Department. S 2214 would permit Interior to exclude from leasing areas of particular environmental sensitivity. Interior would be required to determine whether an activity may result in "significant adverse effect" and to modify, suspend, or terminate the activity to prevent that adverse effect. Royalties would be divided equally between the State and Federal Government. The bill also calls for an energy policy study to be conducted while leasing and development proceed.

HR 3601 was approved by the House Merchant Marine and Fisheries Committee on May 3, 1988. The bill is generally similar to S 2214 in providing for a phased-in leasing program. However, unlike S 2214, it establishes a 260,000-acre protective management zone in the "core calving area" of the Porcupine caribou herd and does not require an energy study. The bill will also be considered by the House Interior Committee, which is headed by Congressman Morris Udall. Chairman Udall favors a wilderness designation for the ANWR coastal plain and has introduced legislation (HR 39) to accomplish that purpose. A similar bill (S 1804) has been introduced in the Senate.

Four committees, House Merchant Marine and Fisheries, House Interior and Insular Affairs, Senate Energy and Natural Resources, and Senate Environment and Public Works have held more than 25 hearings since the debate on ANWR's future began in 1987.

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1. Environmental and Energy Study Conference, "Merchant Marine to Mark Up New Arctic Refuge Leasing Bill," Special Report, Apr. 13, 1988. p. 2.

2. Environmental and Energy Study Conference, "Interior Sets ANWR Hearings," Weekly Bulletin, May 16, 1988. pp. B10-B11.

BOX 1-B

WHAT DID THE DEPARTMENT OF THE INTERIOR CONCLUDE ABOUT THE MAGNITUDE OF ANWR OIL RESOURCES?

The Department of the Interior's conclusions about the magnitude of oil resources in the ANWR coastal plain have been the source of confusion since the DOI ANWR Legislative Environmental Impact Statement was released. The actual conclusion was:

1. There is a 19 percent chance that oil is present in the coastal plain under conditions that would allow commercial recovery (i.e., large quantity in one place, good quality oil, permeable reservoir rock).
2. If oil is present in commercially recoverable form, its estimated mean volume is 3.23 billion barrels of recoverable oil.

In terms of the decision to allow or block leasing of the coastal plain, the DOI assessment means that:

1. There is an 81 percent chance that no commercially recoverable oil will be discovered. In that case, the total impact of leasing will be restricted to the impacts of the exploratory program. No permanent facilities will be built – no pipelines, no production facilities, and no permanent crew quarters.
2. There is a 19 percent chance that commercially recoverable oil will be found. In that case, the expected value of the magnitude of the oil likely to be recovered is 3.23 billion barrels. The value of this oil must be weighed against the effects, negative *and* positive, of building and operating the pipelines, production facilities, and other extensive infrastructure involved in producing this volume of oil in an Arctic environment.

A number of misinterpretations of the DOI conclusions have been communicated to Congress and to the media by both proponents and opponents of ANWR oil development. The following two examples appear to represent the extremes:

- *"The Arctic Refuge coastal plain...is estimated to contain more than 9 billion barrels of recoverable oil, an amount approximately equal to Prudhoe Bay."* Secretary Hodel in the cover letter accompanying the DOI ANWR assessment, April 21, 1987. According to the DOI assessment, the chance of recovering this amount or greater is about 1 percent...it represents the 5 percent probability mark for economically recoverable oil, and the latter occurs with only a 19 percent probability.
- *"There is about a 7 percent chance of finding 3.2 billion recoverable barrels, a 200 day supply (of U.S. oil consumption requirements)."* John Woodwell, Group for Good Government, "Oilscam," January 28, 1988. This value is arrived at by misinterpreting the probability distribution for resource magnitudes in the DOI report. The author notes that the 3.2 billion barrel resource is situated at the 34th percentile on the probability curve, and interprets this to mean that there is a 34 percent chance of obtaining 3.2 billion barrels of oil. Thus, he multiplies .34 by .19, the conditional probability of finding *any* recoverable oil, to obtain "the probability of finding 3.2 billion barrels. However, the proper interpretation is that there is a 7 percent chance of finding *at least* 3.2 billion barrels; this probability includes the potential of finding 8 billion ,9 billion, or even more barrels of recoverable oil. In OTA's view, the most useful interpretation still is that there is a 19 percent chance of recovering oil at ANWR, and if oil *is* recovered, the mean volume is 3.2 billion recoverable barrels.

Also, a number of leasing opponents have presented the leasing decision as a choice between 600 million barrels of oil – the "risked mean" volume of oil, obtained by multiplying 3.2 billion barrels by the 19 percent probability of finding any recoverable oil in ANWR – and the environmental costs of full development, e.g., hundreds of miles of roads and pipelines, thousands of acres of gravel pads, etc. This is an unfair comparison, because full development will occur only if recoverable amounts of oil are found, and the expected volume of this oil is the full 3.2 billion barrels. As noted above, if no commercial oil is found, the impacts will be far less.

"Risked mean" volumes *are* useful when assessing the likely oil resources of an area that includes a *number* of unexplored regions. For example, in assessing the total oil resources remaining in all unexplored regions of the United States, the best estimate of the total resource is the sum of the risked mean oil volumes. However, for these estimates, the risked mean estimates for the individual regions have little meaning.

BOX 1-C
ISSUES AFFECTING THE ANWR DEVELOPMENT DECISION

1. To what extent would development of ANWR oil resources improve U.S. national security and offer significant economic benefits? Are the likely levels of ANWR oil production, if commercial quantities are found, of real significance to U.S. liquid fuels supply? Are predictions of expected declines in North Slope and U.S. oil production levels correct? Is it likely that world oil markets will be under the tight control of the Middle Eastern OPEC countries at the time when ANWR oil could be flowing into the TAPS pipeline?

2. Are there alternatives to developing ANWR oil that likely would prove more effective at lower cost (including environmental cost)? Could improving the efficiency of the automobile fleet save significantly more oil than ANWR could supply? Would pursuit of alternative liquid fuels such as methanol be preferable to investing in marginal U.S. oil resources? What are the risks of foregoing the development of any one alternative, assuming others are pursued?

3. What might be the benefits of delaying the leasing of ANWR, with or without first determining the extent of its oil resources? Is it likely that an accurate determination of its resources could be made without promising that any commercial quantities of oil would be allowed to be developed immediately after discovery? Are ANWR's potential oil resources worth more to the United States in the ground than they are under timely development?

4. Is the ANWR coastal plain truly a unique and irreplaceable wilderness? To what extent are its wilderness values duplicated elsewhere in Alaska? In other words, is developing the coastal plain truly in the same league as developing the Grand Canyon, Yellowstone, or the other "jewels" in our National Parks and Wilderness systems?

5. Could ANWR oil resources be developed without significant damage to the coastal plain's wildlife and other natural resources?

- How have Prudhoe Bay and other North Slope development damaged the natural environment? What are the long-term effects of the hundreds of small oil spills that have occurred? What long-term changes to drainage patterns have occurred because of the extensive road network? What solid and liquid waste problems exist, and what has been their effect? Does the growth of the Central Arctic caribou herd reflect its long-term health, or is the appropriate interpretation less optimistic? What have been the effects of increased air emissions on the North Slope?
- Does current Arctic oilfield technology and practices offer significant environmental improvements over those used earlier on the North Slope? Would problems that existed at the early Prudhoe Bay developments be significantly less of a problem at ANWR because of these changes?
- What differences exist between ANWR and the North Slope/Prudhoe Bay area, and how will these affect the environmental impacts that might accompany development at ANWR?

6. Could ANWR oil resources be developed without foreclosing the eventual return of the coastal plain to a wilderness state? How likely is it that drilling sites can be rehabilitated, roads dismantled, and other physical effects of development successfully removed? Would development be likely to be temporary, or would the building of the needed infrastructure lead to more permanent development and exploitation of other ANWR resources? Would oil development be followed by natural gas development, extending the time frame of petroleum development well past 20 or 30 years?

THE OTA STUDY

At the request of the Senate Committee on Energy and Natural Resources and the House Committee on Merchant Marine and Fisheries, the Office of Technology Assessment has undertaken a study of technologies for Arctic oil production and their effect on future oil production in Alaska and, particularly, in the 1002 area. The OTA study focuses on a *subset* of the issues relevant to Congress' decision on the fate of the area (the full set of issues are listed in Box 1-C), and does not provide guidance on a number of issues critical to the decision. OTA hopes that Congress, in making its decision, will draw on this study in conjunction with an extensive hearing record, several analyses by the Congressional Research Service, the Department of the Interior's Legislative Environmental Impact Statement (LEIS) and its supporting documents, and numerous reports and presentations from Alaskan State government, industry groups, Alaskan Native associations, environmental organizations, and other interest groups and technical organizations.

In addition, a forthcoming OTA study (Technological Risks and Opportunities for Future U.S. Energy Supply and Demand, scheduled for Fall, 1989) will examine topics associated with ANWR's role in future U.S. liquid fuels supply and demand--including future domestic oil production; alternative liquid fuels; the potential for reducing oil requirements by increasing energy efficiency; and the security implications of growing oil imports.

In Chapter 2, this report examines the state-of-the-art of Arctic oilfield technology and attempts to project the nature of technology that might be used in the future to explore, develop, and produce oil in the 1002 area. As part of this evaluation, the report attempts to show how such technology may resemble or differ from the technology used to develop the Prudhoe Bay oilfield, which is the oldest, largest, and most intensively studied of the North Slope oilfields. During extensive congressional testimony on ANWR, advocates and opponents of oil development have argued strenuously about the likelihood that ANWR development would raise many of the same environmental concerns associated with Prudhoe Bay development, and about the importance and accuracy of such concerns. Because the nature of the technology is an important determinant of environmental impacts, this portion of the report should help Congress understand how the impacts of possible future development at ANWR might resemble or differ from the impacts of existing development at Prudhoe. However, the report does not comment on the accuracy of the various claims made about the absolute magnitude of environmental impacts at Prudhoe Bay.

In Chapter 3, the report examines the available estimates of total Alaskan North Slope oil resources and reserves and the projections of future oil production, and evaluates the potential for shifts in future production rates with technology development and changing economic conditions. This evaluation includes an examination of enhanced recovery technologies that might be used to boost North Slope production in the future. The purpose of this portion of the report is to place any future oil production from the 1002 area into a better overall Alaskan and U.S. oil perspective. The report tries here to determine whether or not ANWR oil production represents the only feasible means of maintaining a high throughput through the Trans Alaska Pipeline System to the Lower 48 States for the year 2000 and beyond. Although projections of North Slope production made available to OTA portray sharply declining production in the 1990s, some Members of Congress are skeptical of these projections.

Chapter 2

Technologies for Oil and Gas Development on the North Slope of Alaska

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Chapter 2
Technologies for Oil and Gas Development on the North Slope of Alaska

INTRODUCTION

If oil and gas leasing is permitted in the Arctic National Wildlife Refuge (ANWR), the exploration for and development of any resources discovered there would likely follow the pattern established over the last two decades of commercial petroleum activities on the North Slope of Alaska. The basic oil exploration and production systems for the Arctic have been adapted from technologies used by the industry in less severe environments. These adaptations make it possible to work successfully in the unique Arctic environment of extreme cold temperatures and harsh weather, and to cope with remoteness and the difficulty of transportation. The need to work on permafrost, tundra, and ice also forced some major technological changes. Substantial engineering development was undertaken by the petroleum industry to produce efficient and effective systems for Arctic use. By the early 1980s, after most of Prudhoe Bay and TAPS had been in routine operation for some time, the industry considered that the technology for onshore Arctic operations was proven and mature.[1]

Four Environmental Questions

The debate about whether or not to allow leasing and petroleum development in ANWR includes four key questions about the impact of technologies and practices on the environment:

1. **To what extent will the physical presence of infrastructure associated with oil development disturb ANWR?** How many gravel pads, gravel roads, pipelines, facilities, etc., will cover the tundra? What will be the effect of erosion, disruption of drainage patterns, dust, etc, on local ecosystems? How long will the facilities operate? What is the potential for long-term growth? What regulations could limit environmental disturbance?
2. **To what extent will gravel mining and other construction practices disrupt ANWR?** How much gravel will be needed? What regulatory limits should there be?
3. **How much waste discharge from drilling and production operations will there be?** Will the practices of (and regulation for) managing those wastes be acceptable in ANWR? Is deep well injection a sound practice? To what extent will environmentally benign muds be used? Will reserve pit containment practices be adequate? Will higher environmental standards than normal be necessary for a wildlife refuge?
4. **Will the fresh water needs for ANWR development and standard industry practices for obtaining water be acceptable, feasible, and controllable by regulation?**

This report has focused attention on the first two areas above because they relate most closely to our main objective of characterizing the technological developments likely to occur should ANWR leasing be permitted. The report only briefly discusses the second two areas above. In addition, air quality issues are not addressed. In commenting on the draft report, environmental groups have called attention to their serious concerns about many environmental issues, but most importantly to questions about waste disposal and fresh water supply. The scope of this study has precluded significant environmental analysis. However, if ANWR leasing goes forward, it is clear that all of these issues will continue to be of concern and will need to be addressed in future environmental studies.

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[1] National Petroleum Council, U.S. Arctic Oil and Gas, NPC, U.S. Department of Energy Advisory Committee, 1981.

TECHNOLOGY DEVELOPMENT TO DATE

History

Both the present technology in place and the evolution of Arctic oil and gas technology and practices on the North Slope yield important clues to any likely development of the ANWR coastal plain. The Prudhoe Bay oilfield was developed during the 1970s. During that time, the petroleum industry invested in major engineering projects to enable it to modify technologies developed in other areas for Arctic use. Although the Prudhoe Bay field did not begin production until 1977, pioneering efforts on what was then called the Naval Petroleum Reserve in Alaska (now the National Petroleum Reserve-Alaska [NPRA]) at least 20 years before provided much basic information about drilling in permafrost, use of ice roads and platforms, building gravel pads, and other techniques for working in the Arctic. Other fields were discovered in the vicinity of Prudhoe Bay and put into production using the experience at Prudhoe, to advance technology even further.

All of the producing North Slope fields feed into the Trans Alaska Pipeline System (TAPS). TAPS delivers oil in an elevated pipeline along an 800-mile route from Prudhoe to Valdez, an ice-free terminal in southern Alaska. Research on permafrost along the TAPS route was done during the 1950s and 1960s, and TAPS pipeline technology was developed during the 1970s.

Photo credit: Standard Alaska

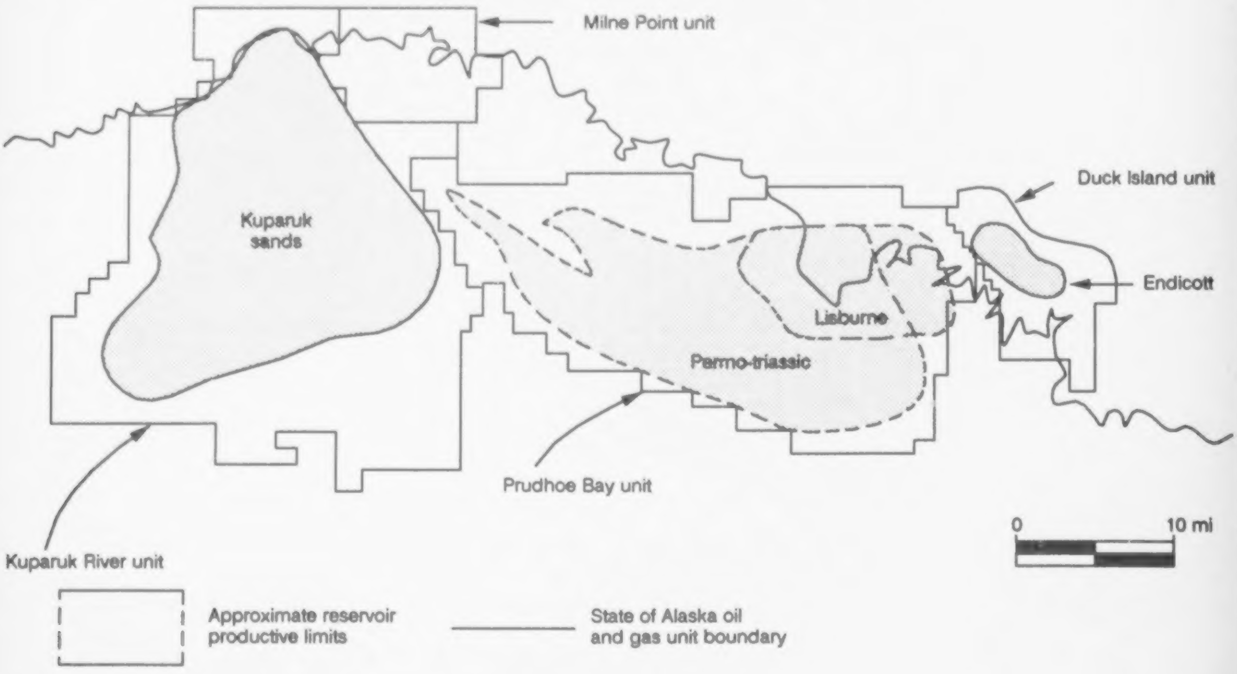
Base Operations Center, Western Operating Area, Prudhoe Bay Field.

Current North Slope Development

Existing North Slope oil and gas development is extensive and still growing.[2] It is concentrated in five fields: Prudhoe Bay, Kuparuk River, Lisburne, Endicott, and Milne Point (Figure 2-1). Currently, all but Milne Point are producing. As a group, the fields are supported by 1,123 miles of pipeline (excluding TAPS) and 346 miles of roads. Some 7,035 acres of land are covered by gravel for facilities, drill sites, roads, and camps. Nine river crossings and three airfields are used for petroleum-related activities. A 370-mile gravel haul road, the Dalton Highway, connects Deadhorse (the operations base for most of the contractors who support the major operations), at the southern end of Prudhoe Bay, with Fairbanks. All the oil is transported via the Trans Alaska Pipeline from Prudhoe Bay to Valdez. The current rate of North Slope oil production is about 2 million barrels per day (mmbd).

Table 2-1 summarizes development activities at the five North Slope sites. Overall, the Deadhorse industrial complex serves as the primary support base for North Slope and Beaufort Sea exploration and development. Deadhorse has living quarters, warehouse facilities, and a paved, State-operated airport. It is located in the southern portion of the Prudhoe oilfield. By itself, the Prudhoe Bay field, the Nation's largest, has two adjacent operating areas, one run by Standard Alaska Production Company (SAPC) and the other run by ARCO Alaska. Production

Figure 2-1.—Alaskan North Slope Producing Oil Fields


Milne Point unit
Duck Island unit
Kuparuk sands
Endicott
Lisburne
Permo-triassic
Prudhoe Bay unit
0
10 mi
Kuparuk River unit
Approximate reservoir productive limits
State of Alaska oil and gas unit boundary

SOURCE: Exxon Co. USA, 1988

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[2] The following description was excerpted from "Five-Year Oil and Gas Leasing Program," a report of the Alaska Department of Natural Resources, Division of Oil and Gas, January 1988.

Table 2-1.—North Slope Petroleum Development Summary (as of October 1987)

Field name	Prudhoe Bay	Lisburne	Kuparuk	Milne Point	Endicott
Discovery date	12/67	12/67	4/69	10/69	3/78
Size of oil pool (sq. mi.)	400	125	400	45	40
Production start-up date	6/77	12/86	12/81	11/85	10/87
Production to date (million bbls)	4,918	5	292	5[a]	[b]
1986 average production rate (barrels/day)	1,554,000	40,000	257,000	12,900	100,000
Remaining reserves:					
million barrels (oil)	4,672	395	1,308	55	375
billion cubic feet (gas)	26,000	625	565	0	730
Existing wells	881	51	557	29	30[c]
Drill sites/pads	38	5	34	4	2
Production centers	6	1	3	1	1
Base camps	2	1	1	1	1
Construction camps	2	0	1	1	1
Power plants	1	1	1	1	1
Topping plants	1	0	1	0	0
Gas compression plants	1	1	1	1	1
Sea water treatment plants	1	0	1	0	1
Enhanced oil recovery plants	1	0	1	0	0
Docks	1	0	1	0	1
Causeways	1	0	0	0	1
Water injection centers	2	0	[d]	[d]	[d]
Associated support and industrial sites	1	0	1	0	0
Airports and company operated airstrips	2	0	1	0	0
Pipelines (miles)	63[e]	[e]	418	15	28
Roads (miles)	218[e]	[e]	94	19	15
Acreage covered (acres)	5,374[e]	[e]	1,409	54	198
River crossings (number)	3[e]	[e]	5	1	1

NOTE: The above does not include the considerable number of support sites and acreage covered at Deadhorse.

[a] Field shut in January 1987.

[b] Production commenced October 1987.

[c] 80-100 wells planned.

[d] Water injection system included in production centers.

[e] Lisburne numbers included with Prudhoe Bay.

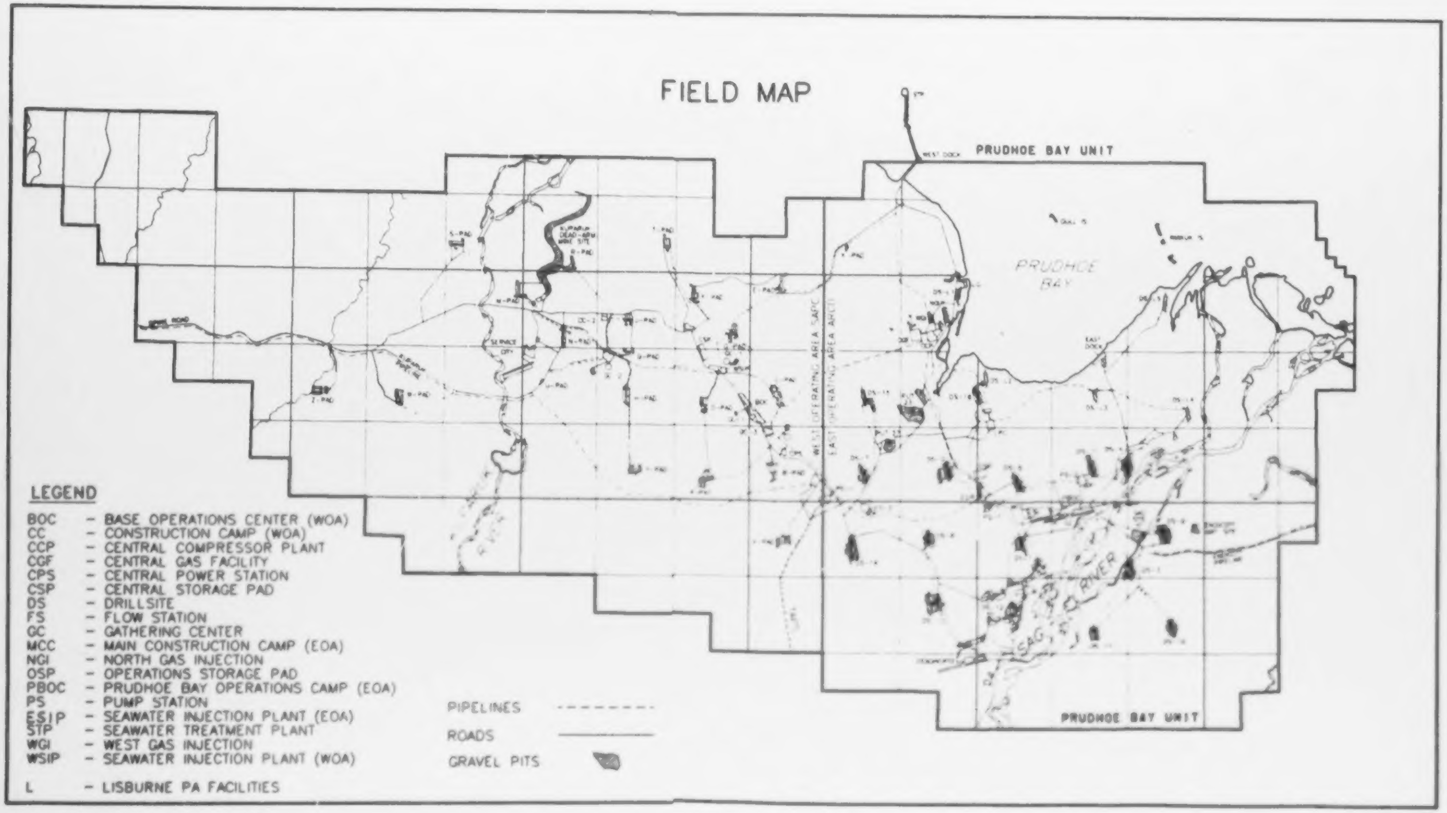
SOURCE: Alaska Department of Natural Resources, Division of Oil & Gas and Exxon comments, Apr. 26, 1988.

began in 1977. Today, Prudhoe Bay facilities are huge. They are located within a 200-square-mile area of the 400-square-mile Prudhoe Bay Unit, and include six oil/gas separation plants, gathering centers or flow stations, 38 drill pads with a total of 828 wells, a central gas facility, a central compression plant, a central powerplant, a field fuel gas unit, a crude topping plant (refinery), a waterflood seawater treatment facility, a gravel airstrip, 200 miles of roads, permanent living quarters, a dock, two construction camps, offices, and two water injection plants.

Figures 2-2 and 2-3 illustrate the large scale of development at Prudhoe Bay. Figure 2-2 depicts the major field production facilities only (drill pads, airstrips, operations center, gas plant, docks, and connecting roads). Figure 2-3 shows more detail of sizes and shapes of facility pads and pipeline networks. While it is difficult to portray the development on this scale, both the extent of coverage and the diversity of the systems in place are evident. Whether (in total) this is a major industrial complex defacing the natural landscape or whether it is only a small, incidental disturbance in a vast wilderness depends mainly on one's values and perception.

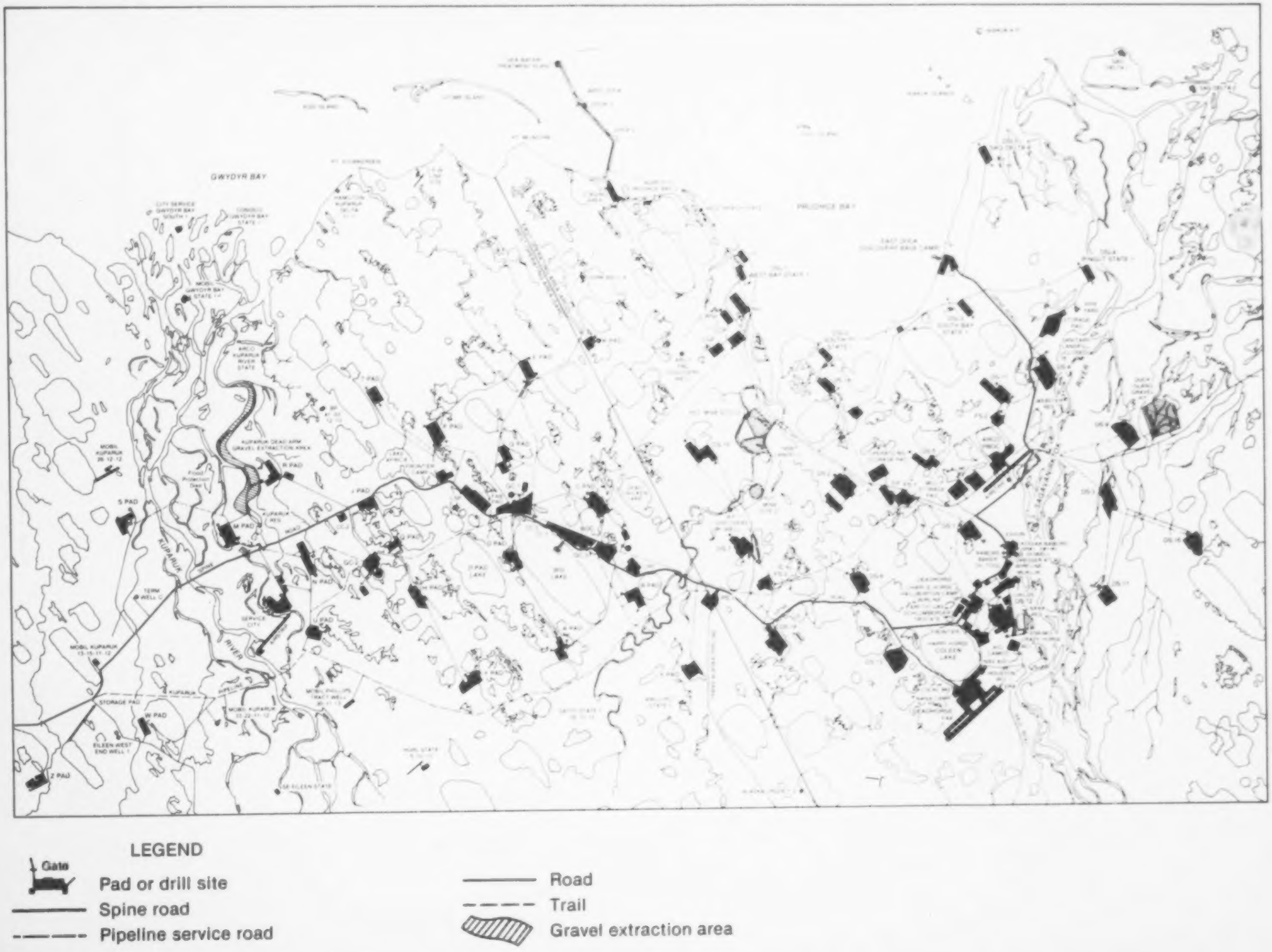
The Kuparuk River field, located about 30 miles west of Prudhoe Bay, is operated by ARCO Alaska. Production began in December 1981. About 500 people will be ultimately employed at the field. Facilities currently include three central production facilities, about 500 wells (800 are planned), the Kuparuk Operations Center (offices and housing for 384 people), the Kuparuk Industrial Center, a gas plant, a seawater treatment plant, pipelines (a 26-mile-long, 24-inch-diameter crude oil line, built in 1984, connects to TAPS at Pump Station 1, and a 26-mile-long, 16-inch-diameter converted oil line carries natural gas to Prudhoe Bay for fuel), 94 miles of roads and a

Figure 2-2.—Prudhoe Bay Facilities Map


FIELD MAP
PRUDHOE BAY UNIT
WEST DOCK
PRUDHOE BAY
WEST OPERATING AREA SAPC
EAST OPERATING AREA ARCO
EAST DOCK
SERVICE CITY
SAG RIVER
PRUDHOE BAY UNIT
LEGEND
BOC – BASE OPERATIONS CENTER (WOA)
CC – CONSTRUCTION CAMP (WOA)
CCP – CENTRAL COMPRESSOR PLANT
CGF – CENTRAL GAS FACILITY
CPS – CENTRAL POWER STATION
CSP – CENTRAL STORAGE PAD
DS – DRILLSITE
FS – FLOW STATION
GC – GATHERING CENTER
MCC – MAIN CONSTRUCTION CAMP (EOA)
NGI – NORTH GAS INJECTION
OSP – OPERATIONS STORAGE PAD
PBOC – PRUDHOE BAY OPERATIONS CAMP (EOA)
PS – PUMP STATION
ESIP – SEAWATER INJECTION PLANT (EOA)
STP – SEAWATER TREATMENT PLANT
WGI – WEST GAS INJECTION
WSIP – SEAWATER INJECTION PLANT (WOA)
L – LISBURNE PA FACILITIES
PIPELINES
ROADS
GRAVEL PITS

SOURCE: Exxon Co. USA, April 1988.

Figure 2-3.—Individual Facilities at Prudhoe Bay


GWYDYR BAY
PRUDHOE BAY
CITY SERVICE GWYDYR BAY SOUTH 1
CONOCO GWYDYR BAY STATE 1
MOBIL GWYDYR BAY STATE 1
ARCO KUPARUK RIVER STATE
KUPARUK DEAD ARM GRAVEL EXTRACTION AREA
Flood Protection Dike
MOBIL KUPARUK 28-12-12
S PAD
R PAD
M PAD
J PAD
F PAD
T PAD
Q PAD
G PAD
N PAD
H PAD
U PAD
KUPARUK RES
KUPARUK
RIVER
SPINE ROAD
TERM WELL C
SERVICE CITY
MOBIL KUPARUK 13-15-11-12
STORAGE PAD
KUPARUK PIPELINE
W PAD
EILEEN WEST END WELL 1
Z PAD
MOBIL KUPARUK 33-22-11-12
MOBIL PHILLIPS TRACT WELL
SE EILEEN STATE
LAKE AFRICA
FRONTIER CAMP
EAST DOCK DISCOVERY BASE CAMP
FS 2
FS 3
DS 4
DS 11
DS 12
DS 14
DS 16
DS 17
HAPPY VALLEY COLLEEN LAKE
DEADHORSE
LEGEND
Gate
Pad or drill site
Spine road
Pipeline service road
Road
Trail
Gravel extraction area

SOURCE: Standard Alaska Production Co., January 1987.

300-foot bridge across the Kuparuk River, a topping plant, two construction camps (one accommodates 650 people and the other 360), and one gravel airstrip.

The Lisburne reservoir was discovered directly beneath Prudhoe Bay. ARCO committed to developing Lisburne in January 1984, and initial production began in December 1986. Of 51 total wells, to date 45 are capable of production. The current production is from 37 of these wells. When completed, about 100 permanent employees will work in the Lisburne field, while about 1,000 will be necessary during portions of the construction phase. Lisburne facilities include one central production facility, five onshore gravel pads, 50 miles of pipeline, and a pilot waterflood project.

The Endicott field, discovered in 1978, is located offshore about 20 miles east of Prudhoe Bay. It is the first oil and gas field to be developed in the Alaskan Beaufort Sea. Standard Alaska Production Company is the operator. Production began in October 1987. The field is being developed from two artificial gravel islands, 2 miles offshore. The islands are connected by 3.1 miles of solid fill causeway and joined to the Sagavanirktok (Sag) River delta by 1.9 miles of gravel causeway with two bridge-type breaches totaling 700 feet and 1.5 miles of onshore causeway through the Sag delta wetlands. A gravel road, 8.7 miles long, connects the causeways with the existing Prudhoe Bay road system at Drill Site 9. An elevated oil pipeline from the field connects with TAPS at Pump Station #1. Other infrastructure includes an onshore gravel pit, a base camp with living quarters for 600 people, a warehouse, offices, fuel tanks, base operations center, seawater intake basin, utilities for the waterflood project, and a dock for sealift operations. Endicott operates with a permit for discharge of drilling effluents into the Beaufort Sea. The North Slope Borough landfill is used to dispose of oil-contaminated drill cuttings, and deep well injection is used to dispose of oil-contaminated fluids.

The Milne Point field was discovered in 1969, and development started in 1979. It is operated by Conoco. The 21,000-acre field is located northeast of the Kuparuk River field. Production, which began in November 1985, was suspended in January 1987 pending an increase and stabilization of oil prices. Facilities include 24 wells on two pads, a 50-person permanent camp, and a 300-person construction camp. About 19 miles of gravel roads connect Milne Point to the Kuparuk spine road, and about 15 miles of pipeline are available to carry oil from Milne Point to the Kuparuk Pipeline. Waterflood infrastructure includes a 45,000-barrels-per-day capacity water injection system.

Camp Lonely, located 80 miles west of Oliktok Point and the Kuparuk field, once served as a staging area for western Beaufort Sea activities but is now mothballed. Infrastructure includes a 100-person camp, offices, carpentry shop, communications shop, sewage treatment plant, generating system, vehicle maintenance shop, a large tank farm, and warm and cold storage warehouses.

In addition to these areas, future development is possible from Niakuk, located offshore between the Lisburne and Endicott fields, the West Sak Reservoir in the Kuparuk River and Milne Point Units, Seal Island, Tern Island, Sandpiper Island, Colville Delta, Flaxman Island/Point Thomson, the Hemi Springs Unit, ARCO Alaska's K-10, and Bullen Point Staging Area.

Arctic Conditions Affecting Technologies

Most experts agree that the major differences between North Slope and Lower 48 conditions that affect the choice and use of oil and gas technologies are the very cold weather, the presence of permafrost, and the remoteness of the area. Designs for technologies for operating at subzero temperatures draw heavily on advanced concepts in metallurgy, elastomers (elastic substances), lubricants, and fuels. The harsh cold environment also has demanded development of new survival systems and procedures to assure personnel safety. All drilling rigs and production facilities where people work must be enclosed, insulated, and heated. Exterior steel structures need to be built from a special arctic-grade steel to prevent brittleness at very low temperatures. Most pipelines and flowlines are insulated, either to prevent water from freezing or to avoid increased viscosity of the crude oil. Shut-in flowlines must be freeze-protected or evacuated and then filled with inert gas.

Permafrost (see Box 2-A) has forced the development of a number of compatible technologies. Because thawed permafrost lacks load-bearing capacity, special construction techniques are used to protect the permafrost layer so that it remains frozen. Where load-bearing is required, common North Slope practice is to build up a thick gravel pad to insulate the permafrost from warmer summer temperatures and from artificial heat sources. The pads then become platforms for facilities, roads, etc. All roads and gravel pads are constructed with a thickness of about five feet of gravel or some alternative, equally effective insulating technique. Flowlines, pipelines, and production handling modules are built aboveground on vertical support

BOX 2-A
PERMAFROST

The entire North Slope of Alaska, including ANWR, is underlain by permafrost, permanently frozen ground extending just below the land surface to as much as 2,000 feet below the surface. In the Arctic winter, the permafrost surface is solid and stable. In the summer, up to several feet of the surface permafrost layer thaw, becoming soft and water-soaked and unable to support even small structures, but the remainder stays frozen. Techniques to provide permanently solid foundations for heated buildings, facilities, roads, etc., on the surface (and to avoid melting the permafrost elsewhere where it is frozen) are therefore necessary for all Arctic operations. With certain types of thaw-stable soils, however, this is less of a problem.

Photo credit: Standard Alaska

Arctic tundra, underlain with permafrost, does not provide a permanently stable foundation.

members (VSMs) to insulate the permafrost from the produced fluids. In special cases where lines must be buried in the permafrost, refrigeration is used around the pipeline. To prevent the casing's[3] vertical movement and its collapse due to permafrost freeze-back after drilling or during well shutdown, casing materials are designed to withstand collapse loads, special cold weather cements are used for the surface casing, and "Arctic Pack" (a gelled freeze-proof diesel that has some insulating properties) is used between the surface casing and production casing. Most development drilling is done from drilling pads, and wells are clustered at the surface on these pads and drilled at an angle to the producing formation. This practice minimizes the amount of construction on and coverage of permafrost.

Because of permafrost there generally is a need for elevated foundations for buildings and facilities and for special containment of fluids and waste discharges. As permafrost is impervious to water, there is no downward percolation of water below mud pits, sewage lagoons, etc.

Photo credit: Standard Alaska

The annual sealift from the Lower 48 to the North Slope brings in thousands of tons of modules.

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[3] Casing is the large steel pipe that lines an oil well. Some casing is installed during drilling operations and, if a well is used to produce oil, additional casing is installed.

There are indications, however, that permafrost is not impervious to other fluids including, perhaps, waste products, and that the migration of these fluids from some reserve pits is an environmental concern.

The harshness and remoteness of the North Slope make the on-site construction of facilities difficult and expensive. It is more cost-effective to start off-site—to prefabricate, to modularize, and to specially transport the needed structures, from 500 tons to 5,000 tons, to their final destination. For the most part, oil facilities for the North Slope are built in modules in the Lower 48, barged to the Prudhoe Bay dock in late summer, off-loaded and moved by crawlers along a gravel road network to a prepared site, and set on preinstalled large diameter piles. The transportation equipment itself has required the construction of special docks and causeways into the Beaufort Sea, especially where near-shore water depths are very shallow. Typically, 8 feet of water at the dock is needed for barge traffic.

Status and Trends of Arctic Technologies

The status of technologies, new developments underway, and needed improvements in exploration, development, production, and transportation systems or practices are summarized below. Table 2-2 lists some of the technologies for these applications.

Reconnaissance Exploration

Exploration begins with reconnaissance. Geological and geophysical surveys are conducted both on the ground and from the air. Gravity measurements are usually taken at ground stations, and magnetic measurements are commonly made with airborne instruments. Seismic surveys, which probe the shape of underground rock formations by interpreting the reflections and refractions of sound waves traveling through the rocks, are usually conducted with ground-based transmitters and receivers. Detailed seismic reflection surveys commonly use either explosives or vibratory sound sources and, when feasible, are usually conducted on the ice or snow to reduce tundra disturbance. In the past, movement of seismic equipment in wheeled vehicles over the tundra when snow cover is thin has left noticeable tracks. Survey technology advancements that could affect future work are automation of data collection and of transmission, processing, and interpretation of data. While these technologies may contribute to more accuracy in future survey work, they do not have much effect on the environment. Exploratory drilling is the activity of most environmental concern.

Drilling and Drilling Systems

Onshore exploratory or development drilling in the Arctic is now routine, using fairly standard technology. A drilling rig with power supply, pipe, casing, mud[4] and cement[5] systems, coring and logging[6] equipment, supplies, base camp for personnel, and ancillary equipment must be moved to the drill site. The drilling site may be a gravel pad, ice pad, or insulated timber pad. Depending on rock conditions, depth of target zone, and other well conditions, drilling may be done only in the winter. Winter drilling has advantages for both movement of equipment (using ice roads and air strips) and for the use of ice pads, because ice pads generally harm the environment less than gravel pads. Depending on the well, drilling may also require additional time and cost. Gravel pads are needed for year-round work. Construction equipment is also needed at an exploratory drill site to build gravel pads, construct reserve pits, and install other support facilities.

Concerns about the impact of drilling technology on the environment mainly center on three principal activities: 1) transportation of equipment to and from the site; 2) building of pads, foundations, and pits at the site; and 3) disposal of wastes or removal of equipment and materials

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[4] Mud is a viscous fluid used to lubricate the drill bit and carry the cuttings to the surface.

[5] Cement is used to fix casing pipe in the well.

[6] Logging is the practice of making measurements in the well with instruments lowered on a cable from the surface.

Table 2-2.—Arctic Oil and Gas Technology: Composite List From Workshop Participants Answering: "What are the best examples of Arctic 'State-of-the-art' technologies?"

A. Exploration/Development
  1. Drilling and Drilling Systems
    a. Drilling Rig/Drilling-Lifting-Pipe Handling:
      - Cantilever rig design capable of drilling on close spacing, easily transported.
      - Top drive rotary system capable of drilling 90 feet at a time without making pipe connections.
      - Automatic pipe-handling systems (off truck and into hole).
      - Iron-roughnecks, hydraulically driven make-up and break-out tongs.
    b. Drillpipe/Bits/Downhole Drills:
      - Improved metallurgy, stronger pipe and casing.
      - Diamond bits capable of long run times.
      - Downhole mud turbines for directional work.
    c. Casing/Cement:
      - Finite Element Analysis for casing connections.
      - Improved metallurgy.
      - Arctic Pak cements for cold hardening.
    d. Circulation (Muds, etc.):
      - Extensive secondary and tertiary mud cleaning equipment; cones, centrifuges. Dry systems.
      - Non-toxic mud systems.
      - Annular injection of unwanted liquid volume.
      - Polymer and mineral oil systems.
    e. Coring and Logging:
      - Improvements in logging tool reliability and capability.
      - High angle holes—drillpipe conveyed; coiled tubing conveyed tools.
      - Measurement-while-drilling (MWD) capabilities—to measure reservoir properties and to guide directional work.
    f. Directional Drilling:
      - MWD tools—continous monitoring of inclination and azimuth. Mud pulse telemetry.
      - Downhole mud turbines, steerable mud motors.
      - Horizontal and near horizontal drilling.
    g. Blow-Out Prevention:
      - Training simulators and improved detection systems.
    h. Permafrost Protection:
      - Arctic pak—freeze-back protection for casing.
      - Arctic cement—set-up prior to freezing; insulates.
      - Thaw bulb computer modeling and monitoring.
      - Refrigerated conductor pipe systems.
  2. Support Systems
    a. Transport of Equipment:
      - Rolligon.
      - Hercules C130 air-transportable rigs and equipment.
      - Hoverbarge.
      - Winter ice road.
      - Conventional barge in summer (offshore island).
      - Ice airstrips for exploration.
      - Highly modularized land rigs for fast moves between exploration wells and efficient moving on pads.
    b. Personnel Support/Camps:
      - Self-contained rig camps (up to 100± people).
      - Construction camps.
      - Isolation/sociological studies.
    c. Supply of Operations:
      - Major equipment and facilities by annual sealift.
      - Motor freight via gravel and ice roads; rolligons.
      - Air cargo (fixed wing plane via ice or gravel strip; or helicopter).
    d. Construction of Drill Pads/Supply Bases:
      - Gravel (5 foot lift for thermal protection).
      - Ice pads for single season exploratory wells.
      - Foam and timber mats for multi-season exploratory wells.
      - "Thin" pads using other insulating materials and less gravel thicknesses.
      - Exploration reserve pits below-ground with permafrost for containment.
      - Development reserve pits below grade contained in permafrost (proposed).
    e. Waste Disposal:
      - Annular injection of liquid wastes.
      - Backhaul of solid or hazardous waste to approved disposal sites.
      - Reduction in waste volumes (distillation).
      - Modular and air transported sewage plants.
      - Encapsulation and refreezing of drill cuttings and mud solids.
      - Washing of cuttings.

B. Production
  1. Well Systems
    a. Casing/Tubing/Perforation/Cementing:
      - Special perforating guns.
      - "Clean" completion fluids.
      - Low-temperature metallurgy.
      - Non-freezing annular fluid for freeze back prevention (Arctic pak).
    b. Wellhead/Flow Control:
      - Computerized gas-lift.
      - Ball valves.
    c. Permafrost Control:
      - Well spacing designed to minimize subsidence due to thaw.
      - Permafrost cement.
  2. Separation and Treatment
      - Compact module designs and overall facility layout.
      - Duplex stainless steel separation vessels.
      - Control systems highly computerized.
  3. Fluid Injection
    a. Gas—Prudhoe Bay Unit Central Compression Plant and upgrades of existing equipment; centralized field-wide gas lift system at Prudhoe Bay with interconnecting tieline between operating areas.
    b. Water—Seawater Treatment Plants at Prudhoe Bay and Kuparuk; incorporation of waterflood system with treated seawater intake and related fieldwide processing facilities into initial production facilities at Endicott; source water injection distribution system with tieline between operating areas at Prudhoe Bay.
  4. Auxiliaries
    a. Power:
      - Generated on site using produced gas/or diesel

(continued on next page)

Table 2-2.—Arctic Oil and Gas Technology: Composite List From Workshop Participants Answering: "What are the best examples of Arctic 'State-of-the-art' technologies?"—Continued

5. Construction Operations
   a. Gravel Pads/Foundations/Site Preparation:
      - Small pad size (5 feet thick).
      - Winter season preferred for construction.
      - Optimum site location to minimize habitat loss, ponding or impoundment, other environmental concerns.
      - Ground surface under some facilities insulated around piles in gravel pads to prevent settlement.

   b. Transportation of Modules:
      - Sealift for large modules; smaller modules by truck on haul road.
      - Large tractors, crawlers, or multi-tiered trailers to move modules.

   c. Construction of Docks/Piers:
      - Slope protection sheetpiles and concrete armor/gravel bags.

   d. Construction of Drainage Structures:
      - Arctic bridges for stream crossings.
      - Culverts and low water crossings for fish passage and erosion control.

C. Transportation
1. Oil through TAPS
   a. Construction of Pipelines/Pumping Stations:
      - Winter construction above ground; summer construction for buried line.
      - Earthquake-proof.
      - Insulated (primarily above ground).

   b. Pipeline Operation:
      - Highly automated.
      - Drag reducing agent to increase throughput.

   c. Permafrost Protection:
      - Heat pipes in vertical support members in permafrost.
      - Refrigerated facility pads.

   d. Controls/Inspection:
      - Highly automated computer controlled.
      - Weekly inspection of line.
      - Automatic monitors and alarms throughout system (leak detection, etc.).

2. Oil Through Norman Wells Pipeline (Canada)
   a. Construction of Pipeline:
      - Winter construction for buried line.
      - Uninsulated.

   b. Pipeline Operation:
      - Operated at ambient temperature (25°F to 35°F) due to high API gravity crude.

   c. Permafrost Protection:
      - Increased pipe wall thickness.

3. Gas
   a. Overland Gas Pipeline:
      - Engineering studies and environmental impact studies underway.
      - TAPS-operated buried fuel gas pipeline.

   b. LNG:
      - Plant under evaluation for Port Valdez to be built in conjunction with gas pipeline from North Slope. provided by local topping plant.
      - Gas-fired or diesel-fired electrical.
      - Large power generation via gas turbines; smaller power needs by diesel fired generators.
      - Kuparuk industrial center for service company support facility.

   b. Hotel and Base Facilities:
      - Production facilities self-contained and largely self-sufficient re: fuel and power generation, water, waste water, sewage treatment, etc.
      - Interiors designed to avert psychological problems linked to darkness and isolation.

   c. Resupply and Transportation:
      - Sealift (short time for open water transport), motor freight, air freight.
      - Icebreaking ships for early supply in spring.

   d. Waste Disposal:
      - Tertiary sewage treatment.
      - Annular injection of liquid wastes.
      - Back haul of solid wastes and hazardous wastes to approved disposal sites.

   e. Roads and Airfields:
      - Gravel (about 5 feet thick), insulation, and geotextile fabric.

   f. Oil Spill Control and Cleanup:
      - Prevention programs and awareness.
      - Specific plans for spill prevention.
      - Environmental response team(s) and equipment trailers.
      - Improved sorbent material and containment booms.
      - Spill reporting procedures.
      - Cleanup and disposal.
      - Revegetation and monitoring.
      - Snow and ice used for containment and sorbent.

   g. Water Supply:
      - Abandoned and flooded gravel pits.
      - Deep lakes.
      - Seawater treatment.
      - Produced water treatment.
      - Water supply wells from fresh water aquifers.
      - Snow control.

SOURCE: Office of Technology Assessment, based on information from: CONOCO; Standard Oil Co.; ARCO Alaska, Inc.; CRREL; and EXXON.

after the completion of drilling. Practices that minimize such impacts are well-known but may limit exploration flexibility or increase cost. For example, working only in winter months and transporting by vehicles only on ice will minimize impacts but may require extra time and cost for an operator, especially when drilling deep or difficult holes.

Circulation Mud

Most drilling operations use a circulation system with a water- or oil-based fluid, called mud. The mud is pumped down a hollow drill pipe and across the face of the drill bit to lubricate it and to remove cuttings. The mud and cuttings are then pumped back up the annular space between the drill pipe and the walls of the hole or casing. Mud is generally mixed with a weighting agent, such as barite, to: 1) stabilize the wellbore and prevent cave-ins; 2) counterbalance any high pressure oil, gas, or water zones in the formations being drilled; and 3) provide lubrication to alleviate problems downhole (such as a stuck pipe).[7]

Drilling fluids are selected based on the types of geologic formations encountered, economics, availability, problems downhole, reservoir damage potential, and well data-collection prac-

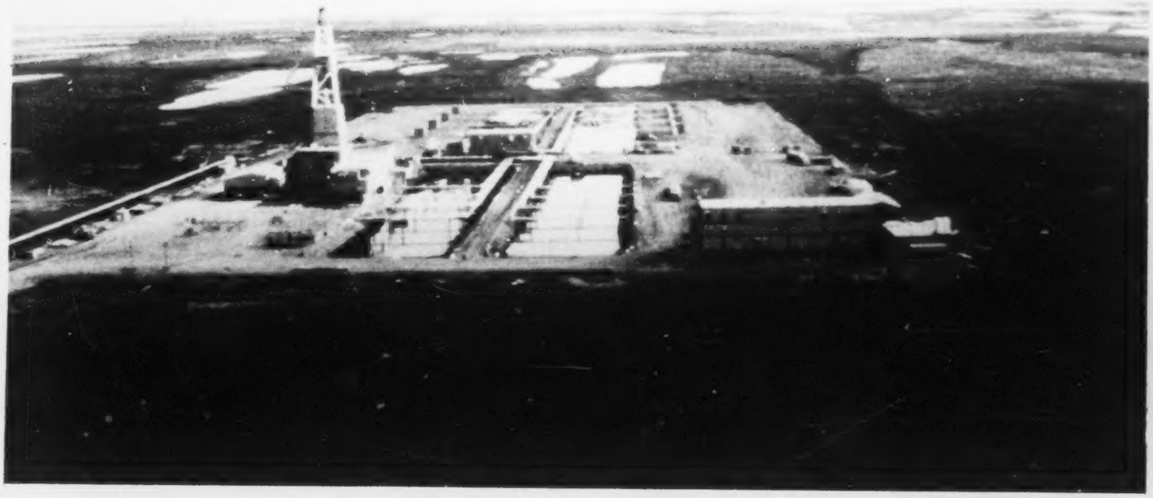

Photo credit: Standard Alaska

Gravel production pad under development on the North Slope. Covered production wells are to the rear of the pad, reserve pits in the center.

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[7] U.S. Environmental Protection Agency, Office of Solid Waste and Emergency Response, Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy, Report to Congress, December 1987. pp. 2-3 to 2-5

tices. Water-based mud with 70 to 80 percent water is the most widely used fluid for all types of drilling in the United States. Colloidal materials, primarily bentonite clay, and weighting materials, such as barite, are common constituents of water-based mud, and small amounts of chemical additives may make drilling easier. Oil-based mud accounts for a small percentage of drilling fluids used nationwide,[8] but is essential for certain types of exploratory wells, directional wells, etc.

The composition of drilling mud and the practices of building reserve pits[9] to contain the fluids have improved over the past decade of Arctic oil operations. The size of reserve pits has been reduced in newer designs, and more recent practices have aimed at better control of the waste products. Smaller reserve pits are possible by recycling muds and injecting unusable liquids down the well's annulus. According to current stated industry practice, when drilling is complete the reserve pit contains only drill cuttings that can be buried or used as fill. Smaller reserve pits also mean smaller gravel drilling pads. Major oil companies operating in Alaska usually follow these and other practices to minimize pad size and reduce wastes.

Figures 2-4, 2-5, and 2-6 show typical operations involving drilling mud and reserve pits. Figure 2-4 shows the standard mud flow pattern from mud pump to drill pipe, down the well and up the annulus, to a shale shaker on the surface which screens out cuttings that are put in a reserve pit. The remaining "cleaned" mud may receive some additives and then return to the mud pump for another cycle. The leakage of mud and other wastes out of reserve pits has been a serious environmental concern in the past. New systems have been developed to address this problem. These new systems would be designed to separate the disposal of cuttings from all fluids and from a pit used as a reserve mud source. The rock cuttings are both comparatively benign and simple to contain in a pit. Figures 2-5 and 2-6 show the location of a reserve pit used just for drill cuttings, a practice that some North Slope operators are reportedly beginning. If this type of system proves feasible, the pit may be covered and permanently contained after drilling is completed. Environmental groups stress the need for long-term monitoring to confirm the permanence of this system.

Directional Drilling

Directional drilling is deliberately drilling at an angle from the vertical to reach a target that is offset from the surface wellsite. Directional drilling was developed specifically for offshore use to allow multiple wells to be drilled from a single platform. Directional drilling on land is used when surface wellheads must be clustered in a small area; one drill pad in the Arctic may contain as many as 40 wells. As directional drilling improves, the number of pads can be decreased and their locations can be more centralized. Currently, North Slope wells are drilled at angles of up to 60 degrees from the vertical with the point of departure from vertical as shallow as 500 feet. Theoretically, a 5,000-acre field, if relatively deep, could be drilled from one site.

Directional drilling to a 60-degree offset is a mature practice on the North Slope. Further developments in directional drilling could allow denser clustering of wells, but changes are expected to be gradual. Continual advancements in offshore extended-reach drilling are helping to cut the high costs of subsea wells; some of these gains may be applied to the North Slope in the future. One North Sea proposal calls for up to a 75-degree angle and as much as 6 mile reach for a research and development well.

Horizontal Drilling

Horizontal drilling, perfected in South Texas tests, is used to improve well flow-rates, especially for thin formations. A conventional directional hole is drilled to a predetermined depth and then, using another drilling method, the hole is drilled at a 90-degree angle from the vertical, as much

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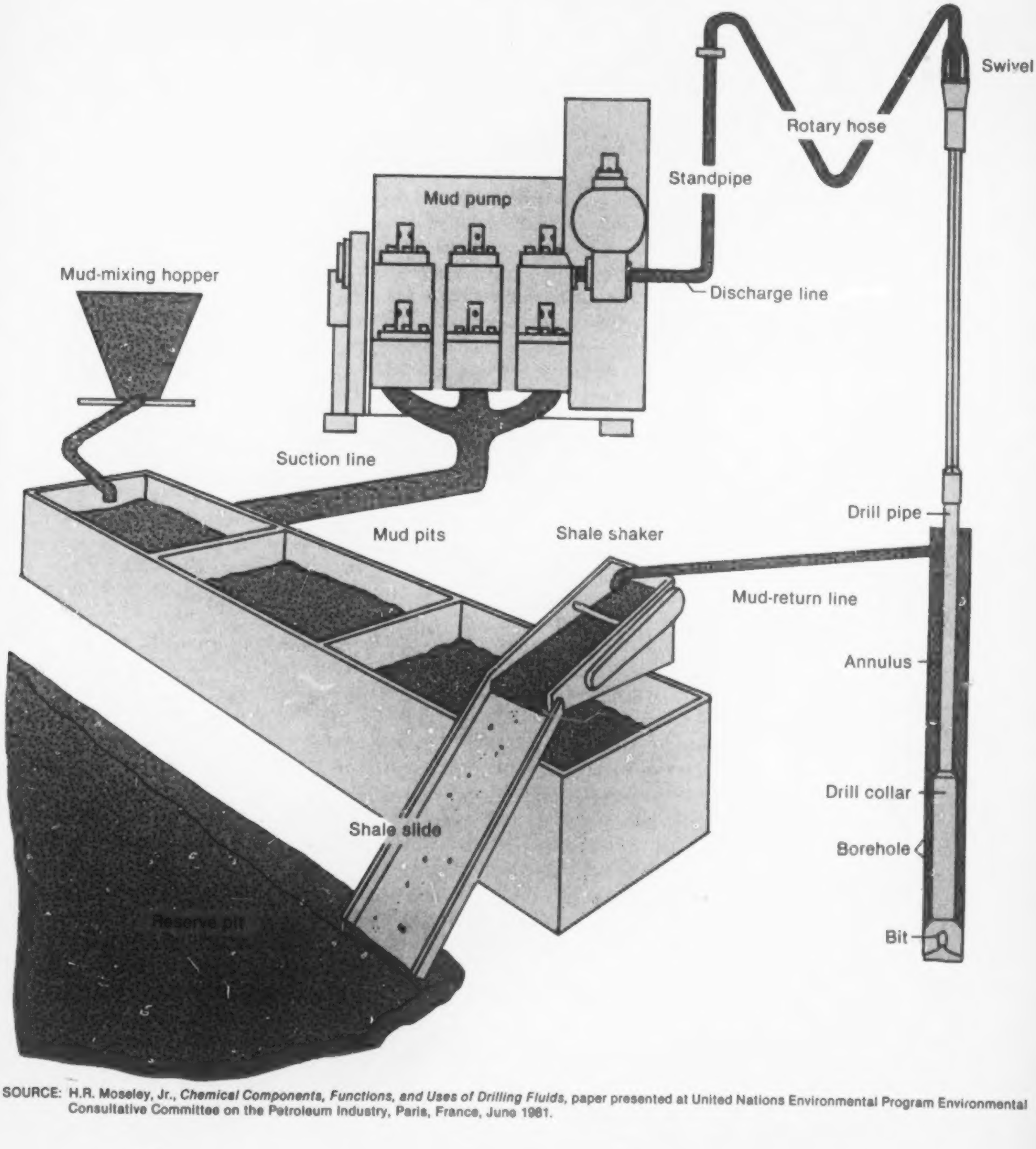
[8] Ibid., pp. 2-5 to 2-6.

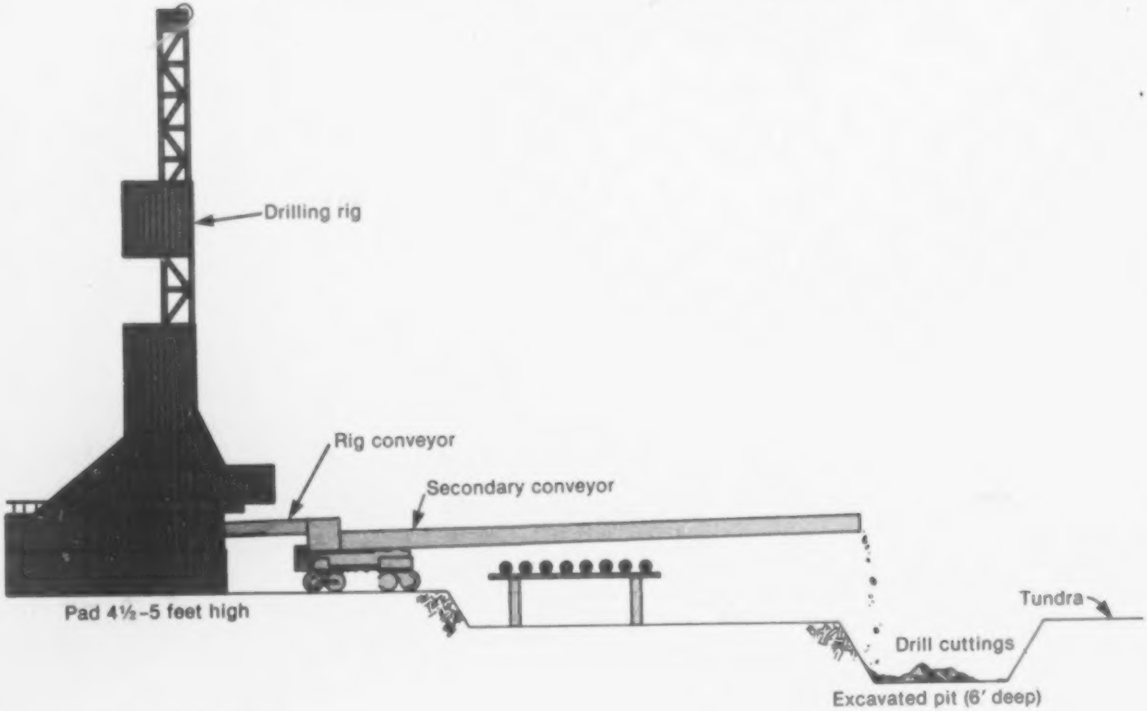
[9] Reserve pits are open pits near a well used to hold excess or waste mud made during the drilling operation. The excess mud is sometimes needed to add pressure to a well during drilling. The pits also serve a disposal function.

Figure 2-4.—Drilling Mud Flow Pattern in a Well


Swivel
Rotary hose
Standpipe
Mud pump
Discharge line
Mud-mixing hopper
Suction line
Drill pipe
Mud pits
Shale shaker
Mud-return line
Annulus
Drill collar
Borehole
Shale slide
Reserve pit
Bit

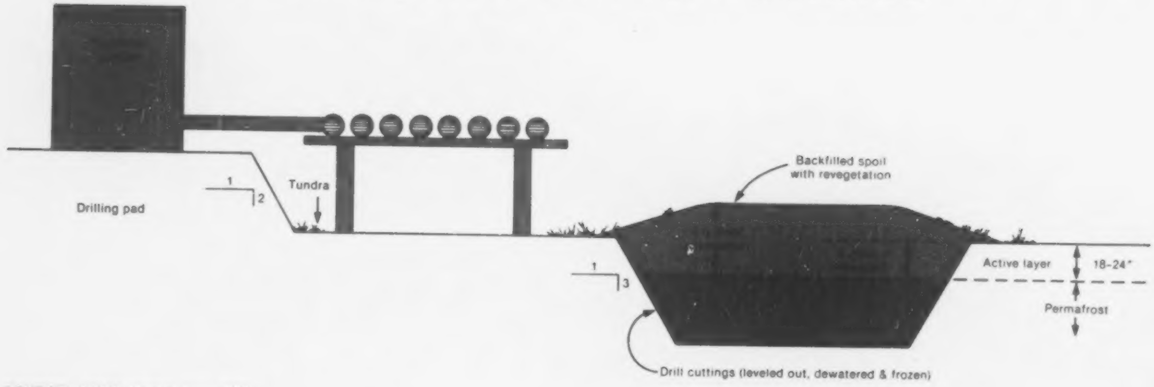
SOURCE: H.R. Moseley, Jr., *Chemical Components, Functions, and Uses of Drilling Fluids*, paper presented at United Nations Environmental Program Environmental Consultative Committee on the Petroleum Industry, Paris, France, June 1981.

Figure 2-5.—Reserve Pit Operations During Drilling (not to scale)


Drilling rig
Rig conveyor
Secondary conveyor
Pad 4½-5 feet high
Tundra
Drill cuttings
Excavated pit (6′ deep)

SOURCE: ARCO Alaska, Inc., 1987.

Figure 2-6.—Reserve Pit Operations During Production (not to scale)

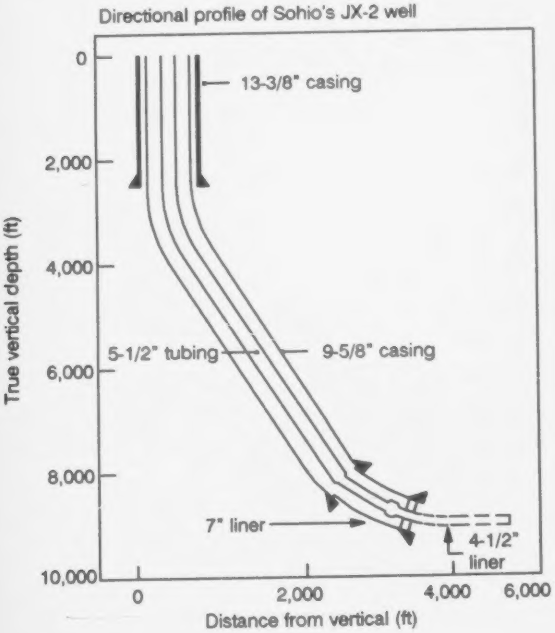

Drilling pad
1
2
Tundra
Backfilled spoil with revegetation
1
3
Active layer
18-24"
Permafrost
Drill cuttings (leveled out, dewatered & frozen)

SOURCE: ARCO Alaska, Inc., 1987.

as 2,000 feet sideways. In the Prudhoe Bay field, two horizontal wells have been drilled that have substantially increased flow rates and that have recovered hard-to-get oil. Figure 2-7 illustrates one of the horizontal wells drilled at Prudhoe Bay to improve recovery in thin portions of the reservoir near the edge of the field. Horizontal drilling could enhance economic recovery rates in some other North Slope applications.

Both directional and horizontal drilling, however, could have some disadvantageous environmental consequences since oil-based muds are more likely to be used to better lubricate the drilling bit. These oil-based muds are more difficult to dispose of in an environmentally sound manner.

Figure 2-7.—Outline of a Prudhoe Bay Horizontal Well



SOURCE: *Oil and Gas Journal*, Feb 17, 1986.

Permafrost Protection

The warmth of produced oil flowing through the upper portion of a well drilled through permafrost will eventually melt the permafrost. Hence, the well casing must be properly designed to prevent thaw and subsidence. The area of the melted permafrost may limit close well spacing, as extensive melting could cause subsidence of other nearby foundations. Nevertheless, work on the causes, extent, predictability, and control of permafrost melting problems is continuing in industry Arctic research and development programs. Results of this work could affect designs of future well sites and drill pad arrangements. For example, some closely spaced surface wells (about 10 feet on center) with special casing have been recently installed at Endicott.

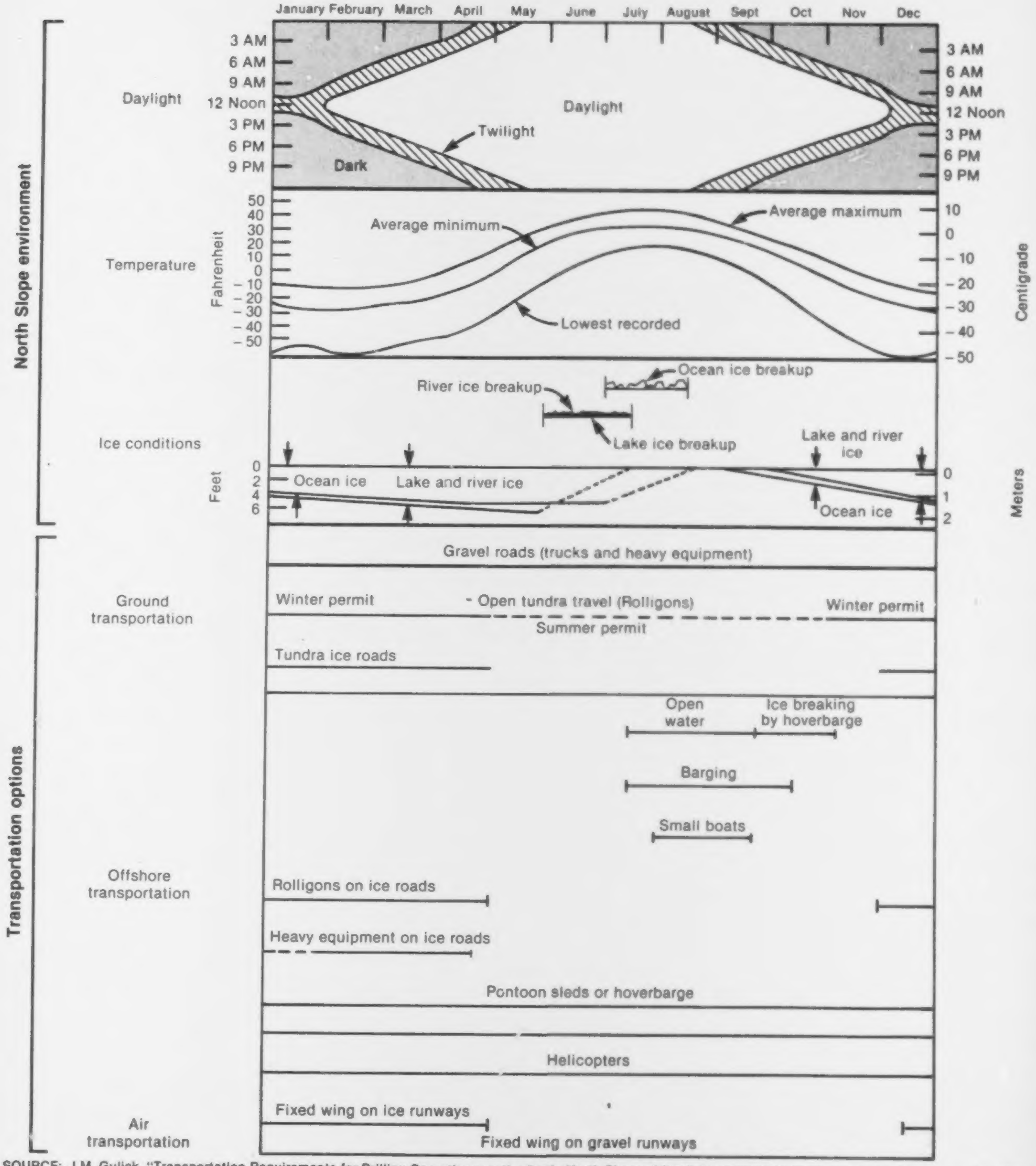
Transport of Equipment

In the early stages of exploratory drilling, transporting equipment is a major activity. To minimize damage to the tundra, winter season movements of heavy equipment on ice roads are preferred. Summer movements may be made by airplane, by barge, or by a specially designed ground vehicle. Vehicles with large, soft tires, called rolligons, have been used, as have air cushioned vehicles. Soft-tired ground vehicle technology is well-established; however, air-cushioned vehicles have not proven very reliable or efficient. Operators usually choose some combination of transport methods to balance cost, environmental protection, and the need for flexibility. Figure 2-8 shows the typical uses of various transportation systems during different Arctic seasons.

New transportation technologies are unlikely anytime soon without more regulatory pressure. Operators may need specific guidelines on the timing or location of movements and on maximum weights, to keep environmental damage down. However, some level of damage to the tundra is unavoidable. Future environmental regulation must evaluate what level is acceptable and what operational controls will assure that operators stay within acceptable limits.

Once a field is discovered and development begins, marine docks and gravel roads needed to receive and transport heavy equipment and

Figure 2-8.—Transportation Options Associated With Changing North Slope Physical Environment



SOURCE: J.M. Gulick, "Transportation Requirements for Drilling Operations on the Arctic North Slope of Alaska," *Journal of Petroleum Technology*, December 1983.

Photo credit: Standard Alaska

Specialized vehicles have been developed to protect the tundra during both summer and winter conditions.

modules to production sites bring more manmade change to the landscape.

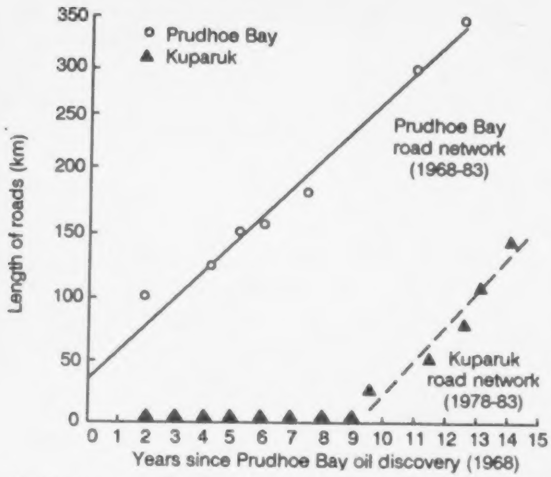
Construction

When a field is developed, onsite construction centers around building gravel pads, roads, culverts, docks, causeways, and foundations (pilings); installing modules; building pipelines, etc. Construction practices have changed over the years since Prudhoe Bay development began—mainly through smaller, more compact drilling pads. However, the typical 5-foot-thick gravel pad, road, or airstrip is reasonably standard and is not likely to be much reduced in size in the near future. Thus, lots of gravel still needs to be mined and moved. Nevertheless, OTA is aware of some insulated gravel pads built in Kuparuk that reduce gravel thickness and, in addition, of the consolidation of facilities to reduce the size of the pads. It is likely that industry's incentive to reduce gravel use is mostly economic. If gravel is easily available and cheap, however, these gravel-reduction measures would not likely be used without regulatory pressure.

Gravel is also used to build roads. Figure 2-9 shows the growth in the length of the road network for both Prudhoe and Kuparuk since they were first developed up through 1983. These data indicate that even 15 years after Prudhoe was discovered, roads were still being constructed at about the same rate as in early years. In 10 years Prudhoe's road mileage tripled. The Kuparuk field is following the same pattern. A corresponding growth in gravel coverage is assumed. While no more recent road coverage data are available, industry claims that gravel coverage leveled off in the last few years.

The continual, long-term growth in the extent of areal coverage of the tundra by manmade facilities follows the gradual and staged nature of the

Figure 2-9.—Growth of the Prudhoe and Kuparuk Road Networks 1968-83



SOURCE: U.S. Army Cold Regions Research and Engineering Lab (CRREL), Disturbance and Recovery of Arctic Alaskan Tundra Terrain," CRREL Report 87-11, July 1987.

development of large oilfields. The first stage of development, when a pattern of primary recovery wells are drilled, can last several years simply because of the large number of wells to be drilled and the economic penalty involved in attempting to complete the drilling quickly by importing large numbers of men and equipment. During this period, the number of gravel pads and the length of the road network grows with the number of wells being drilled. After the initial wells are drilled, after a portion of the field's recoverable resources have been produced, and after the reservoir pressure driving the oil to the wells is somewhat depleted, a second stage of recovery seeks to maintain reservoir pressure by injecting fluids—commonly water, in a "waterflood" operation—into the producing formation. This operation requires additional facilities and (usually) wells for injection, with additional requirements for gravel pads and roads. Further, in a third stage of recovery, heat, fluids, and chemicals are injected into the rock to loosen its hold on the oil not released in the first two stages; these operations may add still further to road and gravel coverage.

Eventually, less geologically attractive drilling targets come into range by using the same infrastructure. New opportunities may open for expanding production through: the development of new, smaller fields; infill drilling; seeking smaller, separate reservoirs within the same field; and drilling on the margins of the field where the oil-bearing formation is relatively thin. As these additional drilling targets are pursued, the road and gravel coverage continues to grow.

Wherever construction operations require heavy equipment and major facilities, accidents or carelessness can cause the discharge of pollutants or unnecessary damage to the tundra, natural stream beds, etc. State regulations try to reduce these risks, but some environmental groups claim that the regulations are not strong enough and that construction over large areas could cause extensive impacts.

Pipelines

Much of today's Arctic pipeline technology was first developed for the Trans Alaska Pipeline System. All developed North Slope fields pump their produced oil by the same kind of elevated pipeline to the TAPS Pump Station #1 at Prudhoe Bay. Refinements have been made in insulation and construction techniques, which make construction more cost-effective. Arctic-grade steel is used for all pipeline vertical support members (VSMs) and other structural components. VSM setting depths are now being adjusted to permafrost characteristics to prevent VSM movement.

Depending on the terrain and excavation necessary, winter-only pipeline construction may be preferred because it offers more tundra protection and, generally, lower cost. For example, winter work from a temporary ice pad or ice road eliminates some of the need for a gravel construction pad or road parallel to the pipeline; road location becomes more flexible. A gravel access road, constructed later, may follow the pipeline but need not parallel it precisely. (Recent studies of caribou movement through pipeline-road corridors indicate that pipeline and road separation of 600 to 800 feet may be necessary for caribou passage). In addition, VSMs can be more firmly set during the winter anyway, when the tundra is frozen. Summer construction is difficult because heavy equipment cannot

Photo credit: BP America Inc.

Mile Zero, Start of the Trans Alaska Pipeline at Prudhoe Bay. The elevated pipeline rests on structures called vertical support members (VSMs).

operate on the thawed tundra and surface water fills up the VSM holes.

Wastes and Waste Disposal

The generation of wastes during oil production is unavoidable. Waste products can be broadly categorized into three types: air pollutants, liquid wastes, and solid wastes.

The principal air pollutants discharged—mainly by natural-gas-fired turbines and heaters—are sulfur dioxide, carbon monoxide, suspended particulate matter, and nitrogen oxides NO_x. Emissions of NO_x range from about 60,000 to 80,000 tons per year.[10] In comparison, about 600 tons of sulfur dioxide, 17,000 tons of carbon monoxide, and 2,000 tons of suspended particulates enter the atmosphere each year from production activities.[11]

Liquid wastes include reserve pit fluids, domestic wastewater, brine discharges, hydrostatic test discharges, vessel rinsates, excavation discharges, oily wastewater streams, workover fluids, waste oil solvents, and others.

Major types of solid waste include drilling wastes, scrap metal, oily wastes, junked vehicles, construction debris, more than 10,000 used drums per year, and other materials.

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[10] Larry Dietrick, Alaska Department of Environmental Conservation, Testimony before the Senate Committee on Natural Resources, Oct. 13, 1987.

[11] ARCO Alaska, Air Issues on the North Slope of Alaska, 1987.

Present Alaskan and U.S. Environmental Protection Agency (EPA) regulations govern waste disposal practices. The industry considers its technology for handling waste to be adequate and does not expect major advances in the near future. Environmental groups, however, point to recent charges of violations of the Clean Water Act and consider waste disposal an important unresolved regulatory issue. The Alaska Department of Environmental Conservation has noted that the North Slope has never been subjected to a detailed evaluation of waste management practices or environmental protection measures.[12] It appears that the industry could continue to improve waste handling practices if requirements become more stringent.

Waste disposal methods consist of well injection, reserve pit use, confinement, recycling, incineration, and landfilling. Most waste generated by oil production on the North Slope is either nonhazardous or is currently exempt from hazardous waste regulation under the Resource Conservation and Recovery Act (RCRA). Environmental groups want to see more exempt wastes redesignated as hazardous, but EPA recently concluded that, pending further study, no significant changes are necessary.[13] Existing practice for wastes designated as hazardous is either to recycle onsite or to ship them out of the State for incineration, recycling, or other disposal.

Deep injection of wastes is a source of controversy in arguments about the environmental impacts of current North Slope development and the potential impacts of future development of the ANWR coastal plain. The controversy stems from the contaminants found in the injected materials, the relative lack of monitoring on the North Slope, the lack of detailed understanding of the geology of the coastal plain, and the history of environmental problems associated with deep well injection in the Lower 48. The types of wastes subject to deep well injection in Alaska are produced water and associated oilfield wastes such as mud. The Alaska Oil and Gas Conservation Commission has primary responsibility for regulating deep well injection. State regulations include requirements for casing and cementing wells to ensure initial structural integrity and pressure monitoring to maintain it.

The basic environmental complaint about deep well injection is the potential for migration of the wastes out of the injection zone and for contamination of shallower aquifers or surface waters. Contamination may occur because of structural failures in the injection wells, unforeseen geological pathways for migration, or the existence of undocumented or improperly plugged wells intersecting the injection zones.

The industry claims that the thick permafrost layers on the North Slope are ample protection against "geological" failures, and that the permafrost layer at ANWR will serve this purpose. Despite these assurances, the Alaska Department of Environmental Conservation is concerned about the potential for unforeseen migration of wastes, especially on the coastal plain where detailed geophysical studies and well data are not available. Problems with well failures—either with the injection well, which is usually a converted production well, or with other wells in the vicinity—have been a concern in the Lower 48, where old wells are used for waste injection in many areas, and undocumented and improperly sealed abandoned wells may serve as pathways to other geologic strata or to the surface. On the North Slope, there are fewer wells, and none are more than 10 or 20 years old. Hence, well failures should not be as big a concern on the North Slope.

Reserve pit wastes, consisting of drilling mud and cuttings suspended in a water or oil base, are another concern. There are over 250 reserve pits in existing developments on the North Slope, with capacities ranging from 4.5 million to 13.5

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[12] Letter to OTA from Brad Fristoe, Alaska Department of Environmental Conservation, May 12, 1988. Fristoe also noted that DEC is in the process of doing this evaluation, which will be used as the basis for developing appropriate stipulations for new areas like ANWR.

[13] U.S. Environmental Protection Agency, op. cit., footnote 7, p. V21-2.

million gallons of used drilling mud and cuttings and associated wastes.[14] Excess reserve pit fluids are either disposed directly onto the tundra or onto roads, or are injected into subsurface formations. The Alaska Department of Environmental Conservation estimates that 100 million gallons of supernatant (i.e., the liquids forming a layer above settled solids in the reserve pit) are pumped onto the tundra and roadways each year to make room for new drilling waste and to avoid overtopping and/or breaching problems. Additional reserve pit fluids may reach the tundra if reserve pits are breached because of poor construction. Approximately 26 million barrels of muds and cuttings are currently impounded in Prudhoe Bay reserve pits.[15]

Liquid reserve pit wastes contain small amounts of metals (e.g., aluminum, arsenic, barium, cadmium, chromium, copper, lead, mercury, nickel, silver, and zinc); aromatic hydrocarbons; and chemical additives. In sufficient quantities and with enough exposure, many of these components of liquid reserve pit wastes can be harmful to aquatic organisms and to waterfowl and other birds (for example, potentially causing bioaccumulation of heavy metals and other contaminants in local wildlife, thus affecting the food chain). EPA notes that the controlled discharge of excess pit liquids has been a State-approved practice on the North Slope.

The Alaska Department of Environmental Conservation, the State agency with primary authority to regulate the design, construction, and operation of reserve pits, now requires that discharges meet State water quality standards. Also, the reserve pit must have been stable (no discharges into the pit) for one freeze-thaw cycle before any discharges can take place. Environmental groups assert that these standards are inadequate to protect aquatic species and that effluents have exceeded acceptable levels in the past. Since a National Pollutant Discharge Elimination System's (NPDES) permit does not cover these discharges, EPA is concerned about the long-term effects of discharging large quantities of liquid reserve pit waste on the tundra. While concerned, EPA notes that the existing body of scientific evidence is insufficient to conclusively demonstrate whether or not there are problems resulting from this practice.[16]

A related concern is the potential unintended breaching of North Slope reserve pits, caused by the intense freeze-thaw cycles that can break down the stability of the pit walls, enabling untreated liquid and solid waste to spill onto the tundra. Some observers also question the advisability of underground injection or permafrost burial of reserve pit waste.

OTA has not addressed the environmental impacts of waste generated by North Slope oil production. Generally, neither the fact that these wastes are generated nor the approximate amounts generated is in dispute. However, there is considerable difference of opinion about the environmental impact of the various kinds of air pollutants and liquid and solid waste products.

The environmental community has issued a detailed report documenting what they believe is significant environmental damage caused by development activities.[17] Environmentalists are concerned that air and water pollution and improper management of hazardous wastes threatens aquatic and terrestrial ecosystems in the Prudhoe Bay area and that similar pollution with similar results will occur in ANWR.

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[14] Trustees for Alaska, Natural Resources Defense Council, and the National Wildlife Federation, Oil in the Arctic, The Environmental Record of Oil Development on Alaska's North Slope, January 1988.January 1988.

[15] Standard Oil, Arctic Oil and Gas Exploration and Production Waste, 1987.

[16] U.S. Environmental Protection Agency, op. cit., footnote 7..

[17] Trustees for Alaska, Natural Resources Defense Council, National Wildlife Federation, Oil in the Arctic: The Environmental Record of Oil Development on Alaska's North Slope, January 1988.

The oil industry, for its part, has attempted to demonstrate that despite some unavoidable consequences of development, "there is no evidence to support the allegation of widespread pollution or to justify claims of significant adverse environmental impact."[18]

The Environmental Protection Agency is cautious in its recent report to Congress[19] but is generally less alarmed than the environmental community about pollution problems and is also less sanguine than the oil industry that there are no North Slope pollution issues of concern. EPA is concerned primarily about the discharge of supernatant onto the tundra and roads, suggesting that further study of impacts is needed.[20] The State of Alaska has recently adopted more stringent effluent limits and has suggested that zero-discharge of industrial wastewater streams should be carefully considered for ANWR.[21]

Water

Substantial amounts of fresh water are used in drilling and other oil production activities. Water supplies in the Arctic are not easily tapped year-round, and some convenient supplies are environmentally unacceptable to use. It is therefore prudent to first reduce water consumption to the most reasonable practical level. Technologies for ensuring environmentally safe water supplies are important. The methods used by industry include trapping and melting snow; insulating small, non-fish-bearing lakes; flooding gravel pits; and desalting seawater.

Among the most abundant sources of water are the gravel extraction pits that have been converted to water reservoirs. Water for many of the Prudhoe Bay well operations is collected and hauled from the Put River pit, a former gravel source that has been flooded and now serves as a year-round water source. Similarly, Mine Site C serves as a water source for the Kuparuk oilfield; this pit is replenished annually with overflow from the Ugnuravik River during break-up.

Desalination of seawater is sometimes a practical option for operations near the coast. If the operation is in the winter, an ice road is constructed to a point where the seawater is not frozen to bottom, the desalination operation is set up there, and fresh water is trucked to where it is needed. This method was used for operations on Challenge Island #1 in the winter of 1980-81 and for Alaska Island #1 in the winter of 1981-82. Desalination of seawater was also used for all the wells drilled from Endeavor Island and Resolution Island and for most of the Niakuk wells. A large desalination plant has been installed at the Endicott field to support production operations. Conoco also used desalination for their Milne Point operations; however, it desalinated water from a 3,000-foot-deep, brackish water, underground aquifer rather than from seawater.

Many operations have had reasonable access to deep lakes. For example, deep lakes in the Sagavanirktok River delta were used for the first three "Sag Delta" wells in the 1970s. Two deep lakes were approved for water sources for operations to the west of the Sag Delta in the winter of 1981-82. No fish were found in either lake, but draw-down restrictions were still applied to protect the few that might have gone undetected.

Deep holes in a river or an oxbow lake are also valuable sources of water. The Alaska Department of Fish and Game applies withdrawal rate, filter size, and draw-down restrictions to all river sources to protect fish. Water for the Niakuk #1 well, for example, came from a deep hole in the Sagavanirktok River. Big Lake, the water source for Standard's Base Operations Camp at Prudhoe, is an example of a lake that has been insulated to minimize freeze-down. For several years it was insulated with styrofoam. Since 1983, however, the lake has been insulated by erecting snow fences that collect drifting snow for insulation.[22]

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[18] Standard Alaska Production Company, Assessing the Impact of Oil Development on Alaska's North Slope: A Rebuttal of the Claims of The Trustees for Alaska, The Natural Resources Defense Council, and the National Wildlife Federation, February 1988., p. 2-6.

[19] U.S. Environmental Protection Agency, op. cit., footnote 7.

[20] Ibid., p. V21-3.

[21] Dietrick, op. cit. footnote 10.

Production Facilities

Production facilities designed to operate for long periods of time with minimal attention must be installed onsite. Directional drilling minimizes the area needed for drill pads and support for wellheads. Characteristics of the oil reservoir will determine the number and location of wells needed, but wellheads can be clustered reasonably close together on individual pads. Wells are needed for both oil production and injection of fluids to stimulate flow. Soil types and permafrost melting characteristics determine the minimum spacing and required support of wellheads on the North Slope.

Production facilities for Arctic use are usually built offsite in large modules (from 500 to 5,000 tons depending on service and distance from dock), in locations such as Washington, Oregon, California, and the Gulf Coast and are moved by barge to coastal docks and then onto pilings and pads at the site. Many kinds of modules are needed to complete a production complex. These include oil/gas/water separation plants, gas injection plants, waterflooding plants, control stations, power-plants, etc. In addition, many support modules are needed, including living quarters, maintenance shops, storage and administrative areas, water and waste treatment, etc. The production field, in time, becomes a network of facility modules resembling a small factory town built on pads and pilings and protected from the harsh environment. Roads, airstrips, and marine docks complete the complex. All these facilities require considerable acreage and thus need a large source of foundation material to build the 5-foot-thick gravel pads commonly used.

Production facilities are added and modified over time as an oilfield is further developed, with the addition of enhanced recovery systems as needed. Each change is usually accompanied by some increase in size, space, and other material needs.

Summary

Arctic oil and gas technology has evolved over the past decade into today's effective and mature industrial system with its accepted commercial operating practices. The recent development of North Slope fields such as Kuparuk and Endicott are the result of this maturity, and any future ANWR development under similar economic and environmental constraints would probably resemble closely these two fields. The industry is confident that this likely extension of current designs and practices is sound development and offers adequate environmental protection. Some environmental groups, however, contend that today's practices are not acceptable for development of ANWR.

While Arctic oil drilling and production technology has matured,the practices for using the technology have improved even further. These improvements have occurred because of both economic and environmental concerns. Practices are likely to continue to improve in ANWR—if it is developed—if economic factors warrant or if environmental requirements are strong. OTA has not evaluated the specific improvements that may reduce environmental impacts, but it appears that extensive debates about environmental protection versus economics will continue if ANWR is leased. Environmental groups have specific concerns that will need to be resolved during the development of regulations for any development that may occur.

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[22] Standard Alaska Production Company, letter to OTA, Feb. 23, 1988.

TECHNOLOGY APPLICATIONS FOR THE ARCTIC NATIONAL WILDLIFE REFUGE

If the Arctic National Wildlife Refuge's (ANWR) coastal plain is leased, the oil industry will apply its broad technological and practical experience in Arctic oil development to the specific conditions of ANWR. The industry generally claims that ANWR exploration and development will look pretty much like the most recent operations elsewhere on the North Slope.

ANWR Special Conditions

OTA has attempted to identify any special or unique conditions of the ANWR coastal plain, as compared to Prudhoe Bay and other North Slope areas, that would affect the technology used or practices followed for petroleum development. The primary data source was our Anchorage workshop and subsequent submissions from industry and other participants at the workshop, as well as extensive comments from industry and environmental organizations that reviewed an earlier draft of this report.

Topographic Relief

The southern part of the ANWR coastal plain has moderate topographic relief, with gently rolling foothills. In contrast, Prudhoe is a very flat thaw-lake plain. ANWR's topography has advantages in that there may be fewer problems with standing water and that there may be better elevated sites for facilities. But there are also disadvantages to the greater relief, including the potential for more problems with channeling and erosion (especially if and when east-to-west roads are built, crossing many streams and requiring attention to drainage patterns) and problems with building roads or locating facilities.

For example, in ANWR, a pipeline can cross gullies and hills more or less in a straight line, but a pipeline access road will need to snake along some surface contours to avoid extensive excavation and filling. A road may also create more environmental problems than a pipeline, especially problems related to drainage, mining gravel, etc. Airstrips need to be reasonably flat; hence, suitable locations in the foothills of ANWR would be more difficult to find than they are at Prudhoe, and, even then, some cutting and filling would have to be done. The same considerations are true for a camp or production facility in ANWR. At Prudhoe, a camp or an airstrip can go almost anywhere that is dry and, for a winter-only exploration well, an airstrip can be constructed even on a convenient frozen lake.

Sea Ice and Port Sites

In general, potential ANWR port sites have deeper water than do Prudhoe sites. Deeper water eases the problem of building docks and means the length of causeways, needed to reach the water depths of about 8 feet required for barges and other shipping, could be reduced. Ice conditions in potential ANWR port sites are generally equivalent to those in the Prudhoe region except in the extreme eastern part of ANWR, where more severe offshore ice conditions may cause problems for shipping.

Gravel Availability

Extensive gravel deposits are located within the ANWR coastal plain, a situation that simplifies finding gravel for construction. Gravel availability in ANWR is similar to that at Prudhoe but better than at Kuparuk.

Permafrost Layer

Some experts believe the permafrost layer in ANWR is thinner than at Prudhoe, but the evidence is sketchy. Permafrost thickness may sometimes affect aspects of well drilling (e.g., the starting depth for directional drilling), but other factors could govern drilling decisions and may be more important. This uncertainty will be resolved only with actual drilling. The permafrost situation in ANWR, however, probably will be handled in much the same way as it is at Prudhoe Bay.

Sites for Deep Injection of Wastes

Knowledge of subsurface geologic conditions for deep well injection is sketchy at this time but is important to locating acceptable sites for waste injection. Prudhoe is considered to have good conditions for containing deep injected wastes. Conditions in ANWR are not defined, although experts disagree about the interpretation of existing evidence. Industry is reasonably confident that suitable sites can be found; however, different experts have different opinions on the extent of tests and study necessary to confirm a "suitable site." This ambiguity is one of the chief concerns of some environmental groups.

Potential Developed Area

The ANWR coastal plain covers about 1.5 million acres. This area is about twice the size of the general region covering the Prudhoe, Kuparuk, Lisburne, and Endicott fields, the major producing North Slope fields. The U.S. Department of the Interior has identified 26 faulted structural prospects within the plain. The mapped and areal extent of these prospects is based on structures defined by seismic data. Thus, the prospects contain potential petroleum traps, but the extent of producible oil is unknown. If these prospects contain oilfields, the largest prospect (227,000 acres) would be similar in acreage to Kuparuk and the second largest (about 130,000 acres) would be roughly the area of the Prudhoe Bay field. All 26 prospects are of a size that could contain fields at least the areal size of the smaller known North Slope fields. While these comparisons are not predictive, they are indicative of the possible extent of surface development if major ANWR discoveries are made. The extent of land coverage for development at ANWR would then likely resemble Prudhoe and Kuparuk and perhaps some smaller fields as well. If several of ANWR's prospects contain economically recoverable oil, the total developed area may be equal to or greater than the developed area of all existing North Slope development.

Water

Whereas industry has made extensive use of existing surface water supplies at Prudhoe, ANWR has few large, deep lakes. Substantial water for ANWR development would probably need to come from other sources. Industry could resort to excavating pits, melting snow, and other water collection techniques, but these activities will likely prove to be more extensive in ANWR than they were at Prudhoe Bay. Industry has also claimed that 12 of the large rivers in the ANWR coastal plain could be sources of water in summer. Environmental groups believe that water supply will require regulatory attention to minimize impacts.

Wildlife

Approximately 200,000 caribou of the Porcupine Caribou herd inhabit the Arctic National Wildlife Refuge from roughly mid-May to late July. The ANWR population vastly outnumbers 15,000-or-so caribou of the Central Arctic Herd that reside year-round in the Prudhoe Bay area; this contrast is probably the most dramatic for wildlife populations in the two areas. Both herds have been increasing in size in recent years. The degree to which the Porcupine herd will be able to acclimate to development compared to the Central Arctic herd is still being debated. The reintroduced musk oxen population in ANWR now numbers about 500 animals; none live in the Prudhoe Bay area. The number of bears and wolves has declined in the Prudhoe Bay area, largely because they are not as tolerant of man as are some other species. Total North Slope wildlife populations however, are not believed to have diminished.

Overview: ANWR Technologies and Practices

The technologies used to explore for and possibly produce any petroleum resources in the Arctic National Wildlife Refuge will most likely resemble those already in place on other North Slope fields. Technology now in use at the most recently developed sites, such as Endicott, has been built to rigid industry design standards for the Arctic environment and is efficient and effective for producing oil from these fields. The industry operators forcefully claim that the technology has been installed and operated with care to avoid unnecessary environmental impacts. In opposition to this claim, the environmental community points to a number of instances where habitat has suffered damage.

OTA has not analyzed the history of accidents, spills, violations, etc., on the North Slope[23] but notes that future regulations will need to be based on an objective analysis of these environmental concerns.

Only oil has been produced from Alaskan North Slope fields to date. While substantial gas reserves have been delineated, no system to transport gas to the major markets has been built. Several methods have been proposed to transport gas but favorable economics and other concerns have prevented their adoption. The technology for Arctic gas production, however, has been in use at Prudhoe where the world's largest gas compression facility is operating and considerable gas handling capability is in place to inject the gas back into the formation.

Most industry experts believe that no major technological breakthroughs are needed to safely and effectively explore for and produce oil at ANWR. They say that the production systems have advanced in practice during the past two decades of Arctic work to an acceptable level, which they believe is demonstrated by smooth and reliable plant operations.

The level of environmental damage that has occurred, however, is vigorously debated. Many of the technological advances in the past 10 years have concentrated on improving operational efficiency. Several of these advancements also appear to reduce environmental impacts, but specific measurements of reduced impact are not readily available. Some advancements include improved waste handling, less toxic discharges from drilling, and reduced needs for gravel pads and roads with possible reduced intrusion on wildlife. Other technological advances have led to more cost-effective operations in the Arctic. These advances include substantial automation of oil field operations, more efficient sub-assembly of modules, and systems for controlling permafrost melting. Modules for production plants are built in complete units in the Lower 48 and moved in large pieces on barges to the North Slope, thus eliminating the need for large and costly construction crews working onsite.

More environmentally important than developing new technologies for use in ANWR is controlling the practices used to apply the existing ones. Operating practices include: transportation of equipment; construction of drilling pads, pipelines, and facilities; selection of drilling techniques; controlling the effects of permafrost melting; and containing and disposing of drilling fluids and other waste products.

Equipment transportation involves moving many very large heavy pieces of equipment with large vehicles over long distances. The tundra is very fragile, and it does not support much weight in the summer months. The construction of pads, pipelines, and facilities are also major activities on fragile ground; a considerable amount of gravel must be mined which can alter the landscape extensively. Drilling techniques can be selected to minimize surface disturbance if wells can be closely clustered on the surface and if rigs are easily moved or set up. Permafrost consideration is critical because uncontrolled melting may cause foundations or supports to fail, resulting in accidents, spills, etc. It is also important to keep any waste products contained and/or to dispose of them properly.

Impacts: ANWR Technologies and Practices

Key technologies and practices with potential for significant environmental stress were analyzed in an OTA workshop held in Anchorage, Alaska in November 1987. The following discussion expands on the workshop's views.

Exploratory Drilling

Exploratory drilling practices in ANWR will likely follow those used in recent exploration wells on the North Slope. Considerations that may affect the environment include the ability of drillers to move rigs and camps to the site, to build temporary pads and other facilities, and then, when work is done, to remove all material with no damage to the tundra. Practices and equipment have been developed over the years in the Arctic to protect the tundra, but economics and work conditions have sometimes ruled out the ideal approach. In any case, careful set-up and quick removal are keys to environmentally acceptable exploratory drilling. Careful set-up probably can be controlled by regulation, but quick removal will depend on conditions – not always predictable – encountered while drilling.

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[23] A comprehensive discussion of environmental impacts on the North Slope from the environmental community viewpoint appears in "Oil in the Arctic: The Environmental Record of Oil Development on Alaska's North Slope," Natural Resources Defense Council, January 1988. Similar discussions from the industry view appear in "Current ANWR Environmental Issues," The Standard Oil Co., August 1987; "Assessing the Impact of Oil Development on Alaska's North Slope," Standard Oil Company, February 1988; and "Alaska Oil and Gas Association Response to Oil in the Arctic by Speer and Libenson, January 1988," February 1988.

Techniques have been developed to build ice roads, ice pads, and ice air strips for winter-only drilling in the Arctic. Moreover, water can be obtained from melted snow, and reserve pits can be encapsulated. In these ways, the impacts of a drilling operation can be readily removed, and there could be little need for gravel excavation or any other disturbance of the tundra except for reserve pits. However, winter-only drilling can have economic and operational disadvantages. Given the added time and costs of winter-only drilling, industry argues for flexible regulations so that they can judge when such practices are truly warranted. Industry also notes that a small risk of a blowout is always present and, if it occurs, the extra time needed to drill a relief well could extend into the thaw season. Environmental groups argue, however, that, given the unique nature of ANWR, very stringent regulations should be applied with minimal flexibility.

Drilling Systems

Most existing Arctic drilling technology likely to be used in all ANWR exploration, production, workover, and service well drilling has been developed to the point of acceptable efficiency. Use of the most advanced of these systems also may lessen some environmental impacts. For example, directional drilling and the close spacing of wells on the surface contribute to the ability to design fewer and smaller drill pads and thus to reduce the quantity of gravel needed and the spatial impact of development. Directional drilling technology is well developed and continues to improve. In recent years, the development of measurement-while-drilling (MWD) systems,[24] computer analysis, and improved survey techniques have significantly improved directional drilling efficiency and directional limits (the angle off vertical that is possible). Improvements expected in the next decade include more comprehensive logging tools deployed during MWD operations, better directional control from the surface, and improved mud systems for reduced torque or drag.

All of these advancements together may lead to closer spacing of wells on drill pads, and to clustering of larger numbers of wells on each drill pad. However, there are many other factors too that will determine the layout of pads and facilities at ANWR. Well spacing will be determined by a combination of economic, environmental, operational, and safety considerations. Specific conditions such as reservoir depth, well drainage area, and permafrost thaw subsidence also will be factors. Recently drilled wells at Kuparuk and at Prudhoe are spaced as close as 30 feet apart; on the Endicott gravel islands, wells are now even more compact, spaced at 10-foot intervals. Depending on actual conditions, ANWR wells would likely be spaced within this range.

Mud Systems

The most likely mud systems in ANWR are those that have been successful in other North Slope fields. Weighted lignosulfonate, polymer, and oil-based mud have applications in Arctic regions but are not unique to Alaskan oilfields. The majority of North Slope drilling operations use water-based polymer and lignosulfonate muds. However, some drilling operations such as directional, high-angle, and horizontal drilling require the lubricating properties of oil-based mud. Also, some coring[25] operations require oil-based mud to lubricate the bit cutting the core and to minimize damage during drilling. Generally, oil-based mud is used for drilling only the short productive intervals in non-conventional wells.

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[24] These systems feature remote sensors that measure angle, location, speed of penetration, and other factors at the bottom of a hole and transmit that information to a driller at the surface without interrupting drilling operations.

[25] The practice of cutting and retrieving a cylindrical piece of the formation during the drilling operations.

Water-based mud usually would be used until the oil-based mud is required. The anticipated advances from horizontal drilling will possibly increase the need for oil-based mud and, if this occurs, greater attention to suitable disposal of oil-based systems may be needed in ANWR. Environmental groups consider the disposal of mud to be an issue worthy of closer attention.

It is not clear whether more stringent requirements for disposal of used mud and cuttings would be necessary in ANWR. Industry asserts that present State of Alaska regulations are adequate and can be followed in ANWR without much trouble. Alaskan regulations – as they apply in a permafrost region such as ANWR – require that the drill solids be de-watered or frozen in place, covered with a membrane to prevent future fluid entry, and covered with gravel and organic soils of sufficient depth to insure that the drilled solids remain permanently frozen. The liquid drilling mud then would be injected into a subsurface zone. This process is commonly called annular injection because the drilling mud is displaced down the annulus between the surface casing and the production casing. Dedicated injection wells are also used. Some environmental groups have substantial concerns about these practices; they advocate higher standards for waste management in a wildlife refuge.

Fresh Water Supplies

Several techniques for supplying fresh water, developed and used at North Slope production areas, are likely to be used in ANWR. These techniques include: creating deep pools that will not freeze to the bottom in or adjacent to rivers/streambeds, creating deep pools in lakes, desalinating seawater, erecting snow fences to trap snow (and then melting it using snow melters), insulating lakes to keep them from freezing to the bottom, and converting gravel extraction pits to reservoirs. For exploratory sites, water could be hauled from approved locations if necessary. OTA has not evaluated the extent to which the effects of these practices have been monitored.

How much water would ANWR need? Standard Oil Company submitted to OTA the following data as typical of the water requirements that may be expected in ANWR exploration.

- 414,000 gallons of water per mile for construction of an ice road; 4,200 gallons of water per mile for daily ice road maintenance.
- 2,500,000 gallons of water for construction of an ice airstrip;
- 2,100 gallons of water for daily maintenance. (Volume would be less if airstrip is built on a frozen lake.)
- 25,000 gallons of water daily for drilling rig and domestic use.

For a typical exploratory well with about 150 days of operations and about 5 miles of roads, Standard Oil estimates that total water consumption would be about 10 million gallons. The U.S. Department of the Interior estimates 15 million gallons for a similar exploratory well.

For development operations, water requirements would depend on the size of the development, the number of wells, and the size of the support camp. Industry claims that ANWR operations would most likely use developed water reservoirs from former river channels deepened by gravel extraction or from the desalination of seawater. Water withdrawn from gravel extraction pits during the winter would be quickly replenished during the subsequent spring snowmelt. Currently, Prudhoe Bay **development** drilling operations consume approximately 630,000 gallons of water per well.

The potential for water supply techniques to damage the environment would need study at each site. The environmental groups may well urge regulatory attention here.

Gravel Pads/Roads, etc

The most likely number, size, and configuration of gravel pads for an ANWR development are difficult to estimate until an actual discovery is made and delineated. Industry believes, however, that less gravel will be required for an ANWR development with today's technology and experience than was required for early Prudhoe Bay development. Most others would agree, assuming equivalent field characteristics and production systems. Improvements in directional drilling techniques and permafrost technology, along with the use of larger, more consolidated and vertically-layered equipment modules and more space-efficient facility designs tend to reduce gravel pad requirements. Improvements in the design of compact pads have already been realized in recent North Slope developments such as Lisburne and Endicott.

Gravel pad design is also affected by the pad's location, insulation needs (to avoid permafrost thawing), stability requirements (to account for permafrost subsidence and requirements for weight support), and site-specific soil conditions.

Characteristics of the actual oil reservoir, however, are the most important factors in determining the most cost-effective design for the total number of wells, the number of wells per pad, and the pattern of positioning well pads over the surface. For example, while compact pad design improvements are evident in Kuparuk, the actual area covered by gravel pads, roads, etc., as a ratio of total field production is much greater in Kuparuk than Prudhoe because Prudhoe is a more productive field with much thicker pay zones, producing higher per-well flows and higher per-pad production. The total area of tundra that would be covered by gravel in ANWR depends most upon whether an ANWR field has characteristics more similar to Prudhoe, with thick, productive reservoirs, or to Kuparuk with relatively thinner and less productive reservoirs.

Pipelines

An elevated pipeline mounted on vertical support members (VSMs) spaced about 60 feet apart with expansion loops every 1,000 feet would be the most likely pipeline design in ANWR. However, Arctic experience in the use of buried ambient temperature lines is growing and may be another option for ANWR, depending on oil characteristics and production rates, environmental impacts, and economics. Depending on soil conditions, it may be desirable to bury the pipeline in some areas and elevate it in others.

Winter pipeline construction practices are likely to be used in ANWR unless a road parallel to the pipelines is needed for other reasons, in which case the road could support summer pipeline construction. The industry favors flexible regulations to allow it to use the best practices for specific circumstances. On the other hand, environmental groups are concerned about excessive flexibility in regulations, especially in sensitive areas.

Construction of Culverts

Construction at ANWR, as with any major petroleum project, is likely to create extensive environmental disturbance, and regulatory controls may be needed. The OTA workshop examined the construction of docks, piers, and culverts—all needed in any plausible ANWR development scenario.

Culvert design and construction, for example, carries several environmental concerns. In the Prudhoe Bay area of the North Slope, drainage patterns are poorly defined and are controlled more by the growth and melting of ground ice than by erosion and transport of sediment. Thus, consideration of thermal as well as hydraulic aspects of drainage design is necessary. ANWR topography is such that drainage design will be very important.

The predominant minor drainage structures are culverts. Culverts must be designed to prevent thaw settlement of the foundation and to support side loads imposed on the culvert. When culverts are built, unstable material is usually excavated and replaced with thaw-stable material.

Environmental groups point to various past problems with culverts. The most common problem is the restriction of fish passage, which may result from excessively high water velocities or from culvert outlets perched above the streambed. Another problem is ponding when culverts are improperly located or placed too high in an embankment and large ponds are formed. Ponding has adverse effects on vegetation and, depending on depth, may either increase or decrease the seasonal thaw. These problems can be minimized by careful planning and location of drainage works and by the use of good maintenance programs.

Technological Change

OTA concludes that technologies likely to be used in the ANWR coastal plain will closely resemble the most recent North Slope developments such as Kuparuk or Endicott. Major changes in technologies are likely to be too slow and gradual to alter the big picture for ANWR development, but a number of factors are involved in this judgment: the definition of technologies considered, assumptions about the development process, and observations about past technological change and the underlying causes.

Definition of Technologies Considered

OTA defines technologies to cover all of the equipment and facilities that are used for exploration, development, and production. Technologies are of course dominated by large structures, pipelines, pumps, machinery, etc., to the extent that change in one small part would not have much effect on the whole.

Development Assumptions

OTA assumes that if ANWR is developed, the industry will be just as able to select technologies that best suit its economic needs as it has in the past. OTA also assumes that economic and other constraints will not change drastically. Since ANWR is similar to Prudhoe and Kuparuk, there is little incentive for industry to make major changes in technologies that have worked well in these two other fields. With few new problems to solve, industry will tend to model the next generation of technology after the best of the past. Of course, new regulatory demands could force consequent technological change at any time.

Past Technological Changes

In two decades of Alaskan North Slope oil development, technological advancement has been fast and many systems have reached what the industry considers a mature state. Standard geotechnical design practices for Arctic permafrost conditions have been developed and tested for well casing, roads, facility foundations and pipeline supports. Low-temperature needs are now filled in metallurgy, elastomers, lubricants, and fuels. Modularization of facilities and their transportation can be also considered mature technology. Maturity also applies to those systems adapted from other regions to meet severe Arctic conditions as well as many systems specifically designed to solve unique Arctic problems.

OTA concludes that these technologies will continue to advance, but at a much slower pace because the need for improvement is less urgent. Just a few years ago when oil prices plummeted, cost reduction pressure was heavy as industry re-evaluated the amount of investment that could be justified for future production. Some drilling technology advancements probably can be attributed to the need to reduce drilling costs. This pressure from low oil prices has begun to level off in the past year and will probably continue at a low level. However, there is evidence that industry-wide technological change will continue to occur; and when developments elsewhere can be applied to the North Slope, they will be. This pressure for technological change will probably be the same in the future as in the past but, when combined with the other elements of change, the likely rate of change is likely to be lower in the future.

In OTA's view the challenge of ANWR development, if it occurs, will be met by the petroleum industry with proven technologies rather than with innovative ones. A big unknown, however, is outside forces – such as major regulatory pressures – that could require changes in technologies. Such changes might come first in methods of waste handling or management or in methods to reduce intrusion on wildlife habitat.

Schedule

Projecting a likely schedule for ANWR development is hard. Much depends on the timing and sequence of events. Table 2-3 shows some actual development histories for North Slope oil fields and two current ANWR estimates.

Judging from Table 2-3, the ANWR schedule is likely to be at least as long as the ARCO and Department of Energy estimates of 10 to 12 years from lease sale to production start-up, and possibly even longer. Considering that it will probably take a few years before a lease sale is completed, a reasonable schedule would be 15 years from today for the start of any substantial production. If a major field is discovered in ANWR (equivalent to Prudhoe or even Kuparuk), one could expect production to span at least 25 to 30 years from start-up. If ANWR development follows common experience in other oil producing regions, and if regulations, technology, and

Table 2-3.—Typical Development Schedules

Development	Years from lease to discovery	Years from discovery to start-up	Total years lease to start
Prudhoe Bay	3	9	12
Lisburne	3	18	21
Kuparuk	4	12	16
Endicott	9	9	18
ARCO Estimate for ANWR[a]	3	9	12
EIA Report[b] (assuming existing procedures)	3	7	10

SOURCES: 1. ARCO Alaska, Inc., *Arctic National Wildlife Refuge Coastal Plain 1002 Area: Development Scenarios and Environmental Issues*, Attachment to written statement of Jim Weeks, Manager, Prudhoe Bay Field Operations, before the U.S. House Subcommittee on Water and Power Resources, October 8, 1987.
2. Energy Information Administration, *Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge*, Revised Edition, SR/RNGD/87-01, October 1987.

price-cost relationships allow, more exploration and discoveries will follow, spanning many years. At Prudhoe, new fields are continuing to be brought into production some 20 years after the first strike.

Experience indicates that, should ANWR exploration proceed and lead to discovery of a major oilfield, commercial petroleum activities on the ANWR coastal plain are likely to continue into the middle of the 21st century. It is also likely that development will use enhanced recovery techniques after production has started.

ANWR Development Scenarios

OTA investigated two plausible scenarios for ANWR development, one done by the Department of the Interior in its LEIS (see Figure 2-10) and one done by ARCO in a presentation to the House Subcommittee on Water and Power Resources in October 1987.

Neither of these two scenarios presents complete details on all major exploration and development steps or activities. For example, neither provides the number of exploratory wells that may be drilled on lease tracts. The ARCO scenario gives only sizes and gravel pad estimates for the drill pads but not for the gravel pads for facilities, pipelines, roads, docks, etc. The ARCO scenario does give an estimate of total affected area. The LEIS details a series of pad areas and gravel requirements but does not relate these to specific facility descriptions, functions, and locations. The LEIS assumes the development of three commercial fields with a total of 3.2 billion barrels of recoverable oil reserves but does not give a reserve figure for each of the three fields. It also does not estimate the production rate. It appears that two of the LEIS prospective areas are the same as the ones ARCO uses as hypothetical examples (prospect 19 and prospect 6 in the LEIS). The ARCO scenario with two fields developed assumes a total of 3.75 billion barrels of recoverable oil reserves and a peak production rate of 935,000 barrels per day.

Despite the discrepancies and gaps in these two scenarios, they are generally similar, and the estimates and assumptions are close. For this reason, OTA was able to use the combined data to prepare its own general but more simplified scenario, adding a few assumptions that were missing. The OTA scenario and its assumptions are shown in Table 2-4, and a corresponding development schedule is shown in Figure 2-11.

Exploration

The LEIS states that three of the four blocks in the ANWR coastal plain are assumed to be leased and one discovery will be on each, but the size of each discovery is not given. OTA assumes that two discoveries will be commercial and that the total reserves will be roughly the average of the reserves assumed by the LEIS and ARCO. As in the LEIS, an additional 1,500 miles of seismic data are acquired on the coastal plain.

Neither ARCO nor the LEIS estimates the number of exploratory wells to be drilled after leasing; OTA assumes that 10 to 20 wells will be required to identify the two fields. (It has been reported in the past that Prudhoe was discovered on the 19th exploratory well and that over 250 exploratory and delineation wells have been drilled overall on the North Slope over the past two decades. Therefore, this assumption appears conservative.) The size and location of the two OTA assumed discoveries correspond to the LEIS and ARCO data.

Figure 2-10.—Development Scenario for Three Major Prospects on the ANWR Coastal Plain, Department of the Interior, Legislative Environmental Impact Statement for the ANWR Coastal Plain

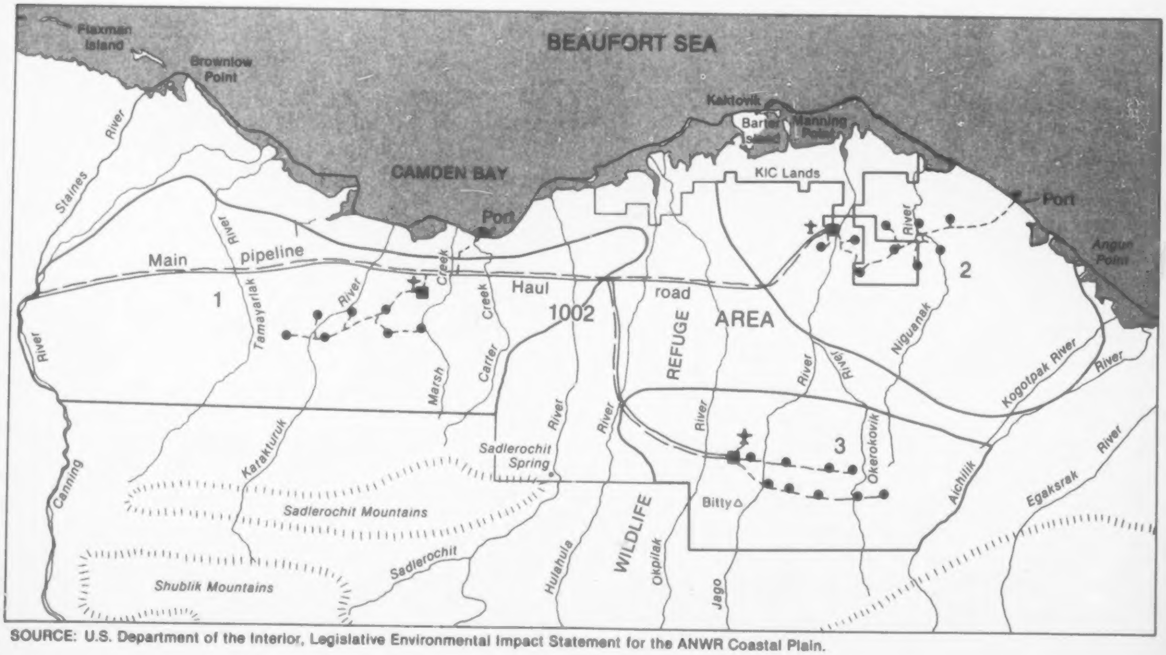
Estimated Linear or Areal Coverage by Selected Facilities

Main oil pipeline within the 1002 area[2]	100 mi (610 ac)
Main road paralleling main pipeline and from marine facilities[2]	120 mi (730 ac)
Spur roads with collecting lines within production fields	160 mi (980 ac)
Marine and salt-water-treatment facilities	2 (200 ac)
Large central production facilities	7 (630 ac)
Small central production facilities	4 (160 ac)
Large permanent airfields	2 (260 ac)
Small permanent airfields	2 (60 ac)
Permanent drilling pads	50-60 (1,200-1,600 ac)
Borrow sites	10-15 (500-700 ac)
Gravel for construction, operation, and maintenance	40 million-50 million cu yds
Major river or stream crossings	Maximum 25

NOTE: Figures given in miles refer to linear miles of the facilities. Areas were calculated on the basis of 50-foot widths each for the main oil pipeline and main road, totaling a 100-foot right-of-way for the main transportation corridor. A 50-foot right-of-way was assumed for spur roads with collecting lines. The numbers of nonlinear units are also provided.

[2] The distance from the 1002 western boundary to TAPS Pump Station 1 is approximately 50 miles, across State of Alaska land. This 50 miles is not included in the mileage estimates.

Location of Selected Facilities in 1002 Area


BEAUFORT SEA
Flaxman Island
Brownlow Point
Staines River
CAMDEN BAY
Port
Kaktovik
Barter Island
Manning Point
KIC Lands
Port
Angun Point
Main pipeline
Haul road
1002 REFUGE AREA
1
2
3
River
Tamayariak River
River
Creek
Marsh Creek
Carter Creek
Canning
Katakturuk
River
River
River
River
River
Niguanak
Kogotpak River
River
Okerokovik
Aichilik
Egaksrak River
Sadlerochit Spring
Sadlerochit Mountains
Shublik Mountains
Sadlerochit
Hulahula
WILDLIFE
Okpilak
Jago
Bitty

SOURCE: U.S. Department of the Interior, Legislative Environmental Impact Statement for the ANWR Coastal Plain.

Table 2-4.—OTA ANWR Development Scenario

Exploration: 3 of 4 blocks leased
Additional seismic surveys—1,500 line miles
10-20 exploration wells drilled
Two commercial discoveries—one large/one small field (equivalent to prospect 19 and 6 in EIS)
Air transport exploration drill rigs—ice pads
#1 Large field—eastern end of coastal plain
#2 Small field—western end of coastal plain

Development:	#1	#2
Field size (billion barrels recoverable)	3.0	0.5
Peak production rate (barrels/day)	700,000	100,000
Number of well sites (Pads)	12	2
Total number of wells	700	100
Central industrial facility	(One similar to Kuparuk for two fields)	
Production facilities	2 large complexes 4 satellite	1 large complex —
Airfields	One large	One small
Port facilities	Port complex near Beaufort Lagoon	Port complex at Camden Bay
Seawater treatment plant	1	1
Oil transport	30" elevated main trunk pipeline, 150 mi. to TAPS Pump Station #1	Spur Pipeline to Main Trunk
Gravel pads/roads/etc.	2,500-3,000 acres	500-1,000 acres
Total "Footprint" incl. main pipeline & road, burrow sites, other disturbances	5,000-7,000 acres depending on final designs	
Total "Sphere of Influence"	150,000—300,000 acres	

NOTE: The assumptions in this table are OTA's but have been reviewed by several industry and government participants in our workshops. While small changes have been suggested, the reviewers generally agree that the numbers are reasonable.

SOURCE: Office of Technology Assessment.

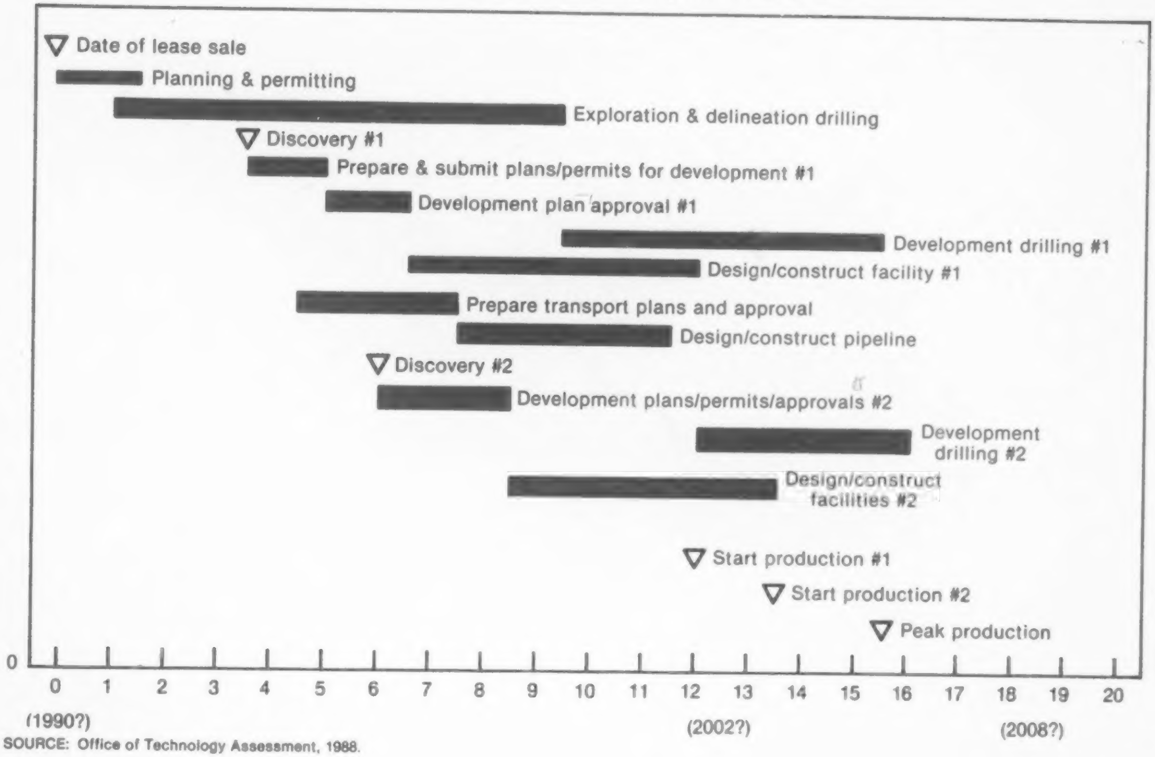
Development

The OTA assumption of peak production rate for the two fields and the total number of wells and well pads roughly corresponds to the ARCO data except that the assumed production rates (as a ratio of recoverable reserves) are somewhat lower. Production rates can be highly variable depending on the actual characteristics of the fields. However, even the OTA numbers correspond to some of the highest production rates from other North Slope fields. For example, discovery #1 is about one-third the size of the Prudhoe Bay field with about half the production rate. It is also about twice the size of the Kuparuk field with about 2.5 times the production rate. Hypothetical discovery #2, on the other hand, is roughly equivalent to the Endicott field which came on-line in 1987.

OTA's assumptions about production facilities are based on both the ARCO scenario and the existing developments at Kuparuk and Endicott. A central industrial facility for the entire ANWR coastal plain would follow the Kuparuk model even though ANWR is somewhat more remote from the other components of the Prudhoe support network. This comparative isolation would probably mean that ANWR would need a larger industrial facility than Kuparuk. Production facilities, airfields, ports, and seawater treatment plants would be similar to those at Kuparuk for discovery #1 and at Endicott for discovery #2. The assumed oil transport pipeline is similar to both the LEIS and ARCO scenarios.

OTA assumptions about gravel pads and road acreage are derived from the LEIS estimates for each field but include neither the main pipeline or road to TAPS nor the other areas of disturbance to the land surface, such as gravel pits. These assumptions, in turn, are all included in the estimate of total "footprint" to be expected from the first development of both hypothetical fields. The projected total "footprint"—area of direct physical coverage—was derived from individual area

Figure 2-11.—OTA ANWR Development Scenario



SOURCE: Office of Technology Assessment, 1988.

estimates, but the high end also corresponds to the ARCO estimate of 11 square miles as the total area affected by development.

Finally, OTA made a rough estimate of the total "sphere of influence" to be expected from full development activities. The notion of a sphere of influence appears in the LEIS as that area surrounding a facility or activity where certain wildlife species potentially would be affected. The actual extent of this sphere of influence would vary depending on the species, and specific impacts are not always quantified. This estimated sphere of influence corresponds, on the high side, to an estimate in the LEIS based on an influence zone of about 3 kilometers around all facilities, pads, pipelines, roads, etc. The upper estimate probably would be relevant only for the more sensitive species. The lower estimate corresponds to the total acreage enclosed by the two hypothetical fields in the scenario. In any case, the total area of 150,000 to 300,000 acres assumed in the OTA scenario could be a considerable portion of available habitat for a number of species.

OTA's estimates are only for initial development of the two hypothetical ANWR fields. Based on experience in all of the other developed North Slope oilfields, it is likely that, after the ANWR fields are producing, a series of modifications will be made. Such activities would include routine maintenance, upgrading, and improvement in recovery and production to extend the life of the field, plus well workovers, infill drilling, addition of secondary and tertiary recovery techniques, and many others. Experience at Prudhoe Bay has shown about a 50-percent increase in the coverage of tundra by gravel roads, pipelines, and facility pads from the time of initial production start-up in 1977 through 1988. Experience at Kuparuk is following the same pattern.

The above scenario for ANWR development can be used to project possible changes to the coastal plain environment that may result. It is clear that the changes could be substantial, to some extent, affecting hundreds of thousands of acres and supporting considerable human and mechanical activity for several decades, and that environmental protection issues would continue to be contentious should such development proceed. The four key principal environmental concerns—physical land disturbance, gravel mining and construction, waste management, and fresh water supply—that are listed at the beginning of this chapter, appear to be of continual future concern. OTA has noted industry's approach to addressing these issues and the fact that many environmental critics believe the industry's approach to be inadequate. Further environmental assessment is probably needed, most importantly in the above four areas, to evaluate the effectiveness and adequacy of these approaches.

Chapter 3

Oil and Gas Production on the North Slope of Alaska

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Chapter 3

Oil and Gas Production on the North Slope of Alaska

INTRODUCTION

The U.S. oil industry and the U.S. Department of the Interior (DOI) contend that unless oil leasing is allowed in the Arctic National Wildlife Refuge (ANWR) and significant quantities of oil are found there, North Slope oil production will soon begin to decline, and that with a decline the United States will become ever more dependent on oil imports.

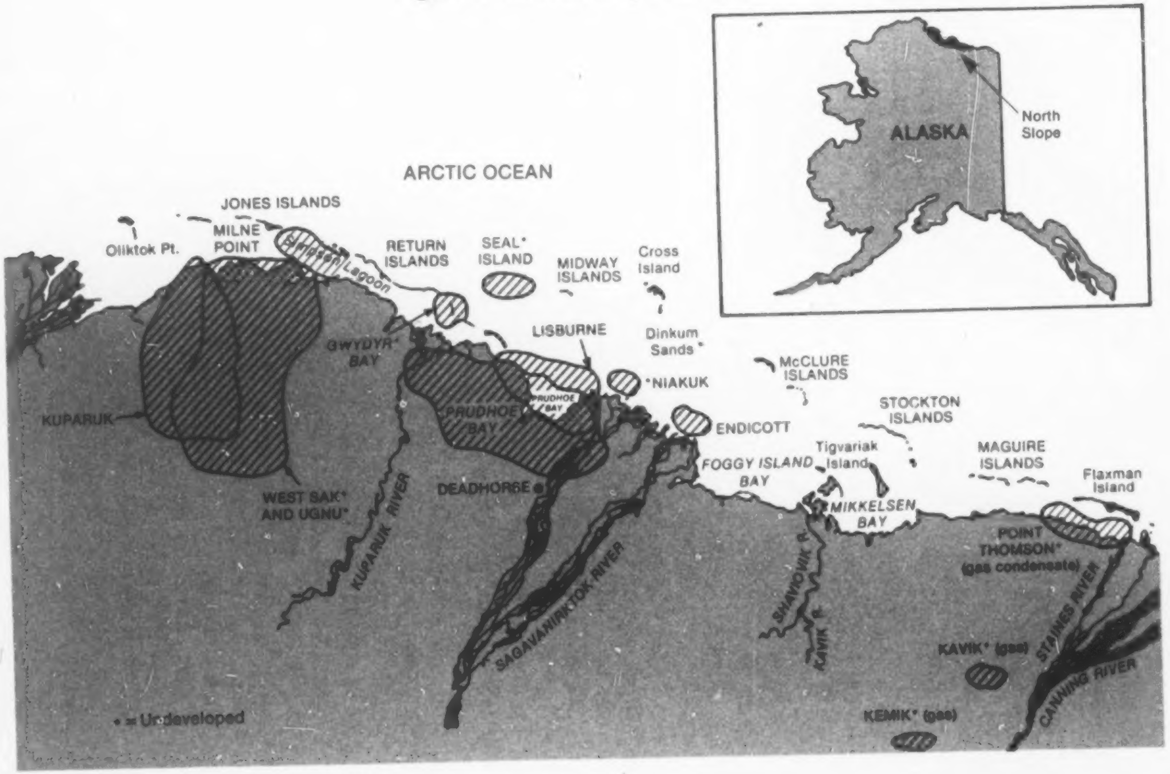
To examine this contention, OTA investigated the status of current production on the North Slope and the potential for additional oilfield development there. In particular, OTA assessed reserves and/or in-place resources in all proven and developed North Slope fields and in known but undeveloped fields where public information is available; assessed what additional production might be expected from these fields in the future as technology improves and/or if additional enhanced oil recovery (EOR) technology is installed; and examined what the contribution to North Slope production from as yet undiscovered onshore and offshore oilfields might be.

Long-term oil production forecasts for the North Slope or, for that matter, for any large area of the United States, are at best gross approximations. Oil forecasts make assumptions about future oil prices, technological developments, environmental requirements, tax and royalty rates, and other variables. Also, forecasts project the success of drilling and other field development activities in areas in which geologic data are often sparse. Finally, forecasts make assumptions about future business strategies, yet company strategies are almost always confidential and, at the same time, subject to change. Consequently, OTA focused its efforts on determining the general production potential of the known fields on the Slope, and on asking the question, "If oil production from the North Slope is not going to decline drastically, where will added production come from?"

We concluded that, although small quantities of additional reserves can be expected from developed, undeveloped, and as yet undiscovered fields on the North Slope, there is no likely source of additional reserves that is large enough to stem a production decline. Thus, North Slope production is likely to begin declining around 1990 – the expected onset of Prudhoe Bay decline – or shortly thereafter. Although the discovery of another Prudhoe Bay-size field in ANWR or elsewhere on the North Slope will help reverse this trend, a field discovered in 1988 would not likely be brought into production before 1998.

As of early 1988, four major oilfields were producing oil in the North Slope of Alaska: Prudhoe Bay, Kuparuk, Lisburne, and Endicott (see Figure 3-1). A fifth field, Milne Point, is developed but not currently producing. In addition to these five oilfields, a number of fields have been discovered but are not yet developed. There are important reasons these other North Slope fields are not yet producing: some may not yet have been sufficiently delineated to determine whether they would be economic to produce; many are too small and/or too far from the Trans Alaska Pipeline System (TAPS) to be economically producible at current market prices; some may have reservoir characteristics that make production difficult and/or prohibitively expensive; and offshore discoveries in more than a few feet of water are currently too expensive to develop and produce. Finally, although many of the best prospects have been tested, only a relatively small portion of the North Slope of Alaska – onshore or offshore – has been explored for hydrocarbons. How much remains to be found is subject to much speculation.

Figure 3-1.—North Slope Oilfields


ALASKA
North Slope
ARCTIC OCEAN
JONES ISLANDS
Oliktok Pt.
MILNE POINT
Simpson Lagoon
RETURN ISLANDS
SEAL* ISLAND
MIDWAY ISLANDS
Cross Island
LISBURNE
Dinkum Sands*
*NIAKUK
McCLURE ISLANDS
STOCKTON ISLANDS
ENDICOTT
Tigvariak Island
MAGUIRE ISLANDS
Flaxman Island
FOGGY ISLAND BAY
MIKKELSEN BAY
GWYDYR* BAY
KUPARUK
PRUDHOE BAY
PRUDHOE BAY
DEADHORSE
WEST SAK* AND UGNU*
KUPARUK RIVER
SAGAVANIRKTOK RIVER
SHAVIOVIK R.
KAVIK R.
POINT THOMSON* (gas condensate)
STAINES RIVER
CANNING RIVER
KAVIK* (gas)
KEMIK* (gas)
* = Undeveloped

SOURCE: Office of Technology Assessment, 1988.

OIL PRODUCTION FROM KNOWN FIELDS

Resource Terms

The total amount of oil in known fields on the North Slope is called "in-place" resources. The amount of in-place oil in known fields that has not yet been extracted is considerable, but only a portion of it is currently economically and technically producible. The amount of in-place resources that geological and engineering studies have shown to be recoverable under current economic conditions using existing technology are known as "proved" or "existing" reserves.[1] "Inferred" or "potential" reserves are those resources that should eventually be added to proved reserves through extensions of known fields, through revisions of earlier reserve estimates based on new subsurface and production information, and through production from new producing zones in known fields.[2] The application of new recovery technology (e.g., enhanced oil recovery [EOR] methods) may also result in additional proved reserves. The term "recoverable" resources is less precise but frequently used. The amount specified by the term is sensitive to changing economic conditions and in this study refers to the sum of proved and potential reserves.

Estimates of in-place and recoverable resources can be made using very little data; of course, the more data available, the more accurate the estimates can be (See Box 3-A). Reserves, on the other hand, are based on drilling results and engineering measurements. Estimates of in-place resources in known fields are ideally based on knowledge of the size of the reservoir; porosity of the reservoir rock; reservoir pressure, temperature, and gas/oil ratio; and amount of water saturation.[3] Recoverable resource estimates use the same type of information, but in addition they generally require information or assumptions about permeability and oil viscosity, which help reservoir engineers determine the degree to which in-place oil is capable of flowing to a wellhead. Recoverable resource estimates also incorporate assumptions about the expected selling price of oil and the technology used to produce it. Reserve estimates require more extensive reservoir and producibility information and assume production at current market prices and the use of existing technology.

BOX 3-A
A CAVEAT

Resource estimation is as much art as science, and numerous pitfalls make accurate estimates difficult. Two typical shortcomings of most estimation techniques are limited availability of data and the need to use simplifying assumptions to make estimates. This situation is why most estimates risk input parameters and report probability distributions. Some of the problems encountered in efforts to estimate North Slope resources are considered in more detail in Appendix A. Often, the assumptions—e.g., oil price or state-of-the-art of technology—on which North Slope resource estimates have been based are not specified or are vague. Although OTA considers the data in this report to be the best data currently available to the public, often there was no compelling reason to select one source of information over another. All resource data in this report should be viewed skeptically and with knowledge of the limitations of resource estimation techniques.

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[1] Joseph P. Riva, Jr., World Petroleum Resources and Reserves (Boulder, Colorado: Westview Press, 1983), Chapter 5, "Reserves, Resources, and Reserves/Production Ratios," p. 124.

[2] Ibid., p. 126.

[3] Ibid.

In-Place Resources of Known Fields

Despite the pitfalls of resource estimation (see Appendix A), the quantity of in-place oil in the developed North Slope fields is reasonably well known from extensive drilling (Table 3-1). Remaining in-place resources in the five developed North Slope fields as of September 1987 are estimated to be about 25 billion barrels. In-place resources of all known North Slope fields may total more than 50 billion barrels. More important is the amount of these in-place resources that is expected to be ultimately recoverable. For the North Slope overall, the recovery efficiency of in-place oil in developed and undeveloped fields is approximately 26 percent.[4] However, recovery efficiencies of individual North Slope fields may vary from 0 percent to perhaps as high as 50 percent, depending on reservoir and fluid characteristics. Resources in some major undeveloped North Slope fields will not be economic to produce unless oil prices rise substantially and/or unless new, less expensive or more efficient production technologies are developed.

Table 3-1.—Minimum Remaining In-Place Oil of Major North Slope Fields As of September 1987

	Billion barrels (rounded)
Proven and developed	
Endicott	1
Kuparuk River	4
Lisburne	3
Milne Point	1
Prudhoe Bay	16
Subtotal	25
Discovered but undeveloped	
Point Thomson (gas condensate)	1
Seal Island	1
Ugnu	6
West Sak	15
Other North Slope	2
Subtotal	25
Total	50

SOURCES: Bureau of Land Management, Anchorage, Alaska; Alaska Department of Natural Resources, Division of Oil and Gas; Institute for Social and Economic Research, University of Alaska.

Estimates of in-place resources of known but as yet undeveloped oilfields on the North Slope are more provisional than those for the five developed fields, and estimates for some discoveries may not yet have been released. Undeveloped oil and gas discoveries on the North Slope include the West Sak and Ugnu fields; the Seal Island and Tern Island discoveries; and the Colville Delta, Gwydyr Bay, Niakuk, Umiat, Kavik, Kemik, and Point Thomson fields (Figure 3-1). Only two of these fields are believed to contain significant in-place resources, and even these two are unlikely to contribute significantly to the North Slope production total in the foreseeable future. Many discoveries are either too small or too far from TAPS or both to be economically producible at this time.

The West Sak and Ugnu reservoirs, both of which generally overlie the Kuparuk River reservoir, deserve special attention due to their huge estimated in-place resources. West Sak contains between 15 billion and 25 billion barrels of oil in-place. ARCO has proved the technical feasibility of producing West Sak oil with existing technology, but the reservoir and oil characteristics (e.g., high oil viscosity, low temperature, shallow depth, complex structure) indicate that recovery will be less than 5 percent of the in-place oil if the field is fully developed using current technology. It appears that some production of West Sak may take place if and when oil prices rise (and stabilize) above $20 per barrel. The Ugnu field contains between 6 billion and 11 billion barrels of in-place resources,[5] but the cost and difficulty of recovery of Ugnu oil will be much greater than for West Sak oil. Thermal stimulation through the permafrost probably would be required to produce the very heavy Ugnu oil, but this technique is likely to be impractical and prohibitively expensive on the North Slope for the foreseeable future.

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[4] U.S. Department of Energy, Energy Information Administration, "Potential Oil Production From the Coastal Plain of the Arctic National Wildlife Refuge," October 1987, p. 18.

[5] W.W. Barnwell and K.S. Pearson, Alaska's Resource Inventory 1984, Special Report 36 (Fairbanks, AK: State of Alaska Department of Natural Resources, Division of Geological and Geophysical Surveys, 1984), p. 9.

Significant gas resources are also found in North Slope fields (Table 3-2). Prudhoe Bay alone contains at least 23 trillion cubic feet of gas considered ultimately recoverable. The distance from U.S. markets and the consequent high cost of building a transportation system for North Slope gas, however, makes it uncompetitive at current gas prices (and at prices corresponding to DOI's oil price scenarios for ANWR development). Neither the proposed Alaska Natural Gas Transportation System nor the competing Trans-Alaska Gas System has secured construction financing or a guaranteed market for the gas it would carry. The Reagan Administration recently determined, however, that North Slope gas could be exported, a finding that may ultimately give a boost to development of North Slope gas, perhaps in the form of Liquefied Natural Gas to Japan. Most of the gas produced at Prudhoe Bay and other North Slope fields is currently reinjected to help maintain reservoir pressure or is used in miscible fluid recovery operations. Some gas is used to operate North Slope facilities. More of this gas may eventually be used on the North Slope to provide the energy required to produce such heavy oilfields as West Sak.

Table 3-2.—Estimated Recoverable Gas in Known North Slope Fields

	Billion cubic feet
Endicott	800
Kuparuk River	600
Lisburne	900
Point Thomson	5,000[a]
Prudhoe Bay	23,000
Total	30,300

[a] No oil or gas is currently being produced from the Point Thomson field. The cost to develop Point Thomson's gas resources would be greater than the cost to develop gas resources in fields already producing oil. Hence, higher gas prices would be needed to develop Point Thomson unless the gas resources were developed in conjunction with the gas condensate and NGLs in the reservoir.

SOURCES: Alaska Department of Natural Resources, Division of Oil and Gas; Standard Alaska Production Co.

Production Constraints

For a number of reasons, oil production on the North Slope of Alaska is more difficult than production in the Lower 48 States. Factors affecting production include the harsh Arctic climate, lack of infrastructure, and great distance from supply sources and markets. The harsh climate of the Arctic is characterized by very low average and absolute temperatures, frequent high winds, and periods of dense fog. Precipitation is low, but snow cover lasts for 8 months or more each year, and blowing snow is common. Low temperatures give rise to permafrost, which may extend 2,000 or more feet below the land surface or seabed, and to sea ice, which can attain average thicknesses of 7 feet or more and persist for as much as 10 months per year in the Beaufort Sea.

Ice affects all aspects of oil activity. On land, the presence of permafrost requires use of special design and construction practices. For instance, well casing must be designed to withstand thaw subsidence stresses that may occur when warm oil flows through the well tubing. Also, all pads and roads must be constructed of gravel about 5 feet thick. Offshore, landfast and moving sea ice, pressure ridges, and other ice phenomena cause problems and added expense for transportation, exploration, and production. All offshore structures must be designed to be able to withstand ice forces.[6]

Lack of infrastructure in the Arctic is another important factor affecting the cost and difficulty of North Slope production. Before Prudhoe Bay was developed, there were no roads, pipelines, or ports on the North Slope and no housing for oilfield workers. Beyond the immediate vicinity of Prudhoe Bay and Kuparuk, this is still the case—for instance, in both the National Petroleum Reserve in Alaska and the Arctic National Wildlife Refuge. Except insofar as development of new fields can take advantage of the infrastructure now in place in the Prudhoe Bay area—more difficult to do as the distance from Prudhoe Bay grows—each new development on the North

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[6] See the Office of Technology Assessment's study, Oil and Gas Technologies for the Arctic and Deepwater, Chapter 3, "Technologies for Arctic and Deepwater Areas" (Washington, DC: Government Printing Office, May 1985).

Slope must be built from scratch. There are no major fabrication facilities on the North Slope, so oil production facilities must be prefabricated in the Lower 48 or overseas and barged north during the summer months or trucked overland. Moreover, except for the few Native North Slope Inuit who work for the oil companies, oilfield workers do not live permanently in the Arctic but are shuttled back and forth on a weekly or biweekly basis between the North Slope and locations either in southern Alaska or – less common now – the Lower 48.

Oilfields close to Prudhoe Bay will be able to connect directly to the Trans Alaska Pipeline System; however, as a field's distance from the pipeline terminus at Pump Station #1 increases, the cost of constructing a connecting pipeline increases. Beyond a certain distance, it may not be economically feasible to construct a small-diameter pipeline connecting with TAPS, and other transportation alternatives will need to be considered. The use of ice-strengthened tankers, for instance, has been considered for transporting any oil found beneath the Chukchi Sea, off Alaska's northwestern coast. For producing oil from offshore fields, pipelines must either be buried below the depth of sea ice scour or mounted on expensive and environmentally controversial causeways.

These production constraints – isolation, lack of infrastructure, and harsh climate – are all important reasons why the minimum economic field size (MEFS) required for development increases greatly with increasing distance from Prudhoe Bay. The other significant determinant of the MEFS is the price of oil. The Seal Island discovery is only 12 miles from Prudhoe Bay, but, given its offshore location in 39 feet of water, it is not economic at current market prices – even though its recoverable reserves are estimated to be at least 300 million barrels. The areawide MEFS for onshore ANWR development is estimated by the Department of the Interior to be 440 million barrels, given a market price of $33 per barrel of North Slope oil (1984 dollars) in the year 2000. If oil prices are significantly lower than this in 2000 (e.g., at $20 per barrel in 1984 dollars) and costs remain the same, the MEFS for ANWR could easily surpass 1.5 billion barrels, assuming that the calculation of the MEFS for ANWR is correct (OTA has some doubts about this calculation; see Box 3-B on page 104).[7] At distances even further from Prudhoe Bay, in the Chukchi Sea for instance, the MEFS could conceivably be 2 billion barrels or more.

The cost to transport oil from remote North Slope fields to Pump Station #1 and from this point to market is an important factor in determining the MEFS. Total transportation costs averaged about $6 per barrel to transport oil from Pump Station #1 to southern markets in 1987. This oil must travel 800 miles south through the Trans Alaska Pipeline, where it is loaded onto tankers at Valdez and shipped either to the West Coast of the United States or to the U.S. Gulf Coast (after being off-loaded on the Pacific side of the Isthmus of Panama, piped across the Isthmus, and reloaded onto other tankers). If the market price of this delivered North Slope oil is near $17, as it was in January 1988, suppliers would be able to charge $11 at Pump Station #1. The price at the wellhead – given that there is a charge for transporting oil from the wellhead to Pump Station #1 – would be even less. For instance, the Milne Point wellhead price would be $7.70, the Endicott price $9.25, the Kuparuk price $9.61, the Prudhoe Bay price $11.00, and the Lisburne price $11.10. For the 6-month period of September 1987 through February 1988, composite wellhead prices for the North Slope decreased from $13.00 to $9.40 per barrel for 27° API crude oil.[8] From per-barrel prices must be subtracted per-barrel capital and operating expenses, taxes, royalties, and the like. Clearly, some of the North Slope producers are operating on a thin profit margin at current market prices. Evidence of this is that the Milne Point field has been shut down since January 1987.

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[7] U.S. Department of the Interior, Arctic National Wildlife Refuge, Alaska, Coastal Plain Resource Assessment, Final Legislative Environmental Impact Statement, April 1987, p. 79.

[8] Alaska Department of Natural Resources data reported by the Oil and Gas Journal.

Reserves and Production

Total oil reserves as of January 1988 from proven and developed fields on the North Slope of Alaska are estimated by the Alaska Department of Natural Resources (DNR), Division of Oil and Gas, to be between 5.25 and 8.22 billion barrels with a mid-range estimate of oil reserves of about 6.5 billion barrels (Table 3-3).[9] This range brackets most other estimates that have been made. Total reserves are sensitive to the price of oil. With low prices, it may not be economical to continue infill drilling beyond a certain point, and the use of EOR techniques may not be economically justified. As prices rise, oil companies are able and willing to expend more money to extract additional oil by implementing EOR techniques and by increasing infill drilling.

Table 3-3.—Estimated Remaining Recoverable Oil As of January 1, 1988 (millions of barrels)

	Low <$15[1]	Mid $18-$20[2] (1987 $)	High <$24[3]
Proven and developed			
Endicott	270[4]	370	445
Kuparuk River	600	900	1,100
Lisburne	280	380	580
Milne Point	0	60	95[5]
Prudhoe Bay	4,100	4,800	6,000
Subtotal	5,250	6,510	8,220
Discovered but undeveloped			
Gwydyr Bay	0	0	10
Niakuk	0	55	75
Point Thomson	0	0	350[6]
Seal Island	0	0	300
West Sak[7]	0	500	1,500
Subtotal	0	555	2,235
Total	5,250	7,065	10,455

[1] All low estimates assume infill drilling will be less than the number of wells forecast for the mid-range estimate.

[2] All mid-range estimates assume that existing technology is used, that no new enhanced oil recovery operations are implemented, and that reservoirs perform as expected.

[3] All estimates assume more infill than for the mid-range forecast and that additional secondary recovery and/or EOR is implemented and successful.

[4] Also assumes waterflood is not successful.

[5] Also assumes Cretaceous sands are developed.

[6] Primarily gas condensate. This is a natural gas reservoir with 5-trillion cubic feet of recoverable gas and a thin "rim" of underlying crude oil.

[7] Also assumes operating agreement signed.

SOURCES: Alaska Department of Natural Resources, Division of Oil and Gas; West Sak estimate from ARCO Alaska, Inc.; Niakuk estimate based on discussion with Standard Alaska Production Co. officials.

The difference between the high and low estimates in Table 3-3 is accounted for largely by different assumptions about price, success of EOR operations, and amount of infill drilling likely to be done. The low estimate assumes that oil prices are less than or equal to $15 per barrel (in 1987 dollars) and that infill drilling is less than expected by DNR for the mid-range estimate. The mid-range estimate assumes that oil prices are $18 to $20 per barrel, that existing technology is used, that no new enhanced oil recovery operations are implemented, and that reservoirs perform as expected. The high-range estimate might be reached if oil prices rise above $24 per barrel and if additional EOR operations are implemented and successful.

If the high-range price assumption is realized, the Division of Oil and Gas also expects additional oil recovery from discovered but as yet undeveloped North Slope fields, principally the West Sak, Point Thomson, Seal Island, Niakuk, Colville Delta, and Gwydyr Bay fields (Table 3-3). The West Sak field has the potential to contribute the most additional oil from known but undeveloped fields, but there is a wide range of opinion about the amount of oil ultimately recoverable from West Sak. The current ARCO estimate of West Sak's recoverable reserves is much lower than the Division of Oil and Gas estimate.

While there are large amounts of oil in the ground on the North Slope, most of the reserves in producing fields are located in the Prudhoe Bay and Kuparuk River fields. Currently, TAPS is running at just about full capacity with oil from the Prudhoe Bay, Kuparuk River, Lisburne, and Endicott fields. As of spring 1988, the pipeline can carry a maximum of 2.2 million barrels of oil per day, although this capacity could be increased somewhat by installing additional pumps and/or by adding more friction-reducing additives. About 1.55 million barrels per day are produced from Prudhoe Bay, 300,000 from Kuparuk River, 100,000 from Endicott, and about 50,000 from Lisburne, a total of about 2.0 million barrels, comprising roughly 24 percent of the daily U.S. domestic oil supply.

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[9] William Van Dyke, Alaska Department of Natural Resources, Division of Oil and Gas, personal communication, January 1988.

According to current estimates, North Slope production may begin declining sometime around 1990 (Table 3-4). Some believe this forecast of decline in 1990 is unduly pessimistic, given that estimates of the onset of decline have been revised several times in the past and that the impact of technological improvements cannot be entirely foreseen. Whatever the exact date of the onset of decline, Prudhoe Bay, whose production dominates that of other fields (in 1986 it accounted for 82.8 percent of Alaska's production), is now considered a mature field, and production there must soon begin to slow. Some of the smaller North Slope fields will also begin to decline in the next few years. By 2000, TAPS throughput is expected to be at best 50 percent of current throughput, even with incremental additions from currently planned EOR operations in existing fields and from possible production in several new fields (Figure 3-2). Production could be as low as 25 percent of current throughput by 2000 if low-range reserve estimates prove more accurate.

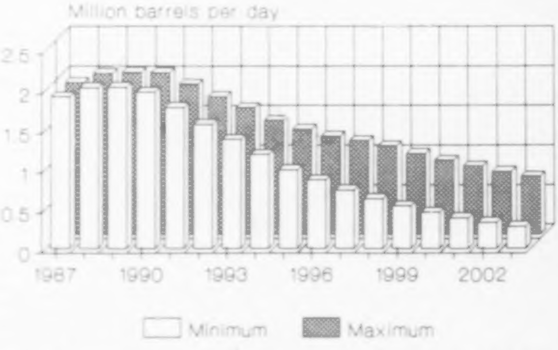
Table 3-4.—Projected TAPS Throughput
(thousand barrels per day)

Year	Maximum	Minimum
1987	1,908	1,908
1988	2,024	2,024
1989	2,040	2,030
1990	2,033	1,968
1991	1,891	1,776
1992	1,735	1,565
1993	1,591	1,371
1994	1,430	1,182
1995	1,317	991
1996	1,233	863
1997	1,176	736
1998	1,110	625
1999	1,013	533
2000	931	453
2001	857	385
2002	789	327
2003	726	278
Total	23,804	19,015

SOURCE: Alaska Department of Natural Resources, Division of Oil and Gas (1987-1999); consensus from OTA workshop (2000-2003).

Production forecasts have been made by the Energy Information Administration, the Alaska Department of Natural Resources, the Alaska Department of Revenue, and others. The data presented in Table 3-4 and Figure 3-2 was recently compiled by the Alaska Department of Natural Resources, but it is representative of other forecasts as well. Most of the difference between the maximum and minimum North Slope production profiles depends on whether or not Milne Point is restarted and Niakuk, West Sak, Gwydyr Bay, Seal Island, and Colville Delta are developed in the early 1990s. Starting production at these fields depends on the price of oil, but it is impossible to specify the exact price at which each field would be developed. Milne Point—currently shut-in due to low oil prices—may be producing again shortly, and Niakuk is said to be commercial at current oil prices, but the other fields probably will not be developed until the price of oil rises and stabilizes in the area of $24 per barrel. Recent strides in cost control could conceivably lower the breakeven price for production from these fields, and recent remarks by ARCO Alaska, Inc. suggest that breakeven prices have indeed come down.[10]

Figure 3-2.-Projected TAPS Throughput
Million Barrels Per Day



SOURCE: Alaska Department of Natural Resources, Division of Oil and Gas.

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[10] ARCO Alaska, Inc., "Security Analyst Meeting," Mar. 30, 1988. ARCO notes that "the majority of capital associated with the exploration program and development of exploration successes is viable in the $15 to $25 a barrel range," p. 29.

Significant North Slope Oilfields

All oilfields are different, not only in their location, size, structure, and other reservoir characteristics, but also in their response to EOR stimulation, their production profiles, and the recovery expected from each.

Prudhoe Bay

Prudhoe Bay is the largest oilfield in the United States and the 18th largest in the world. It is estimated to have had original recoverable oil of 10 billion to 12 billion barrels. Of this amount, 4 billion to 6 billion barrels remain. The lower figure for Prudhoe Bay's remaining recoverable oil includes oil recovered using primary and currently in-place waterflood and miscible fluid recovery technologies. The higher, more optimistic figure assumes the success of enhanced oil recovery projects that could begin in the future, more infill drilling, and a gradual rise in the price of oil.

Prudhoe Bay oil has a large gas cap and is contained in a high-quality, well managed reservoir, as is reflected by its relatively high estimated recovery factor. Approximately 45 percent of original in-place resources are expected to be recovered. The principal producing formation of the Prudhoe Bay field is the Ivashak Sandstone of the Sadlerochit Group. This sandstone consists primarily of two fine- to medium-grained pebbly sandstone sequences separated by an interval dominated by massive conglomerates. The depth of producing zones is between 8,000 and 9,000 feet.

To stimulate additional recovery at the Prudhoe Bay field, waterflooding (injection of water into the reservoir to drive additional oil to producing wells) began in 1984. With this technique, field operators expect to recover 1 billion more barrels of oil than would otherwise have been possible (included in the above estimate of recoverable oil). In addition, Prudhoe's miscible fluid operation began in December 1986 with the installation of the world's largest natural gas plant. The facility produces miscible injectant (MI – a mixture of natural gas and natural gas liquids; see Technologies for Improved Recovery later in this chapter) from raw plant feed gas stripped from well fluids. The MI is injected into the reservoir with alternate injections of water to stimulate additional oil recovery. The operation also currently produces 50,000 barrels per day of natural gas liquids which are blended into the crude oil stream in TAPS.[11] Remaining residue gas is reinjected into the reservoir to maintain gas cap pressure. The operators estimate that the project will allow 5 percent additional oil recovery beyond the waterflood operation for that part of the reservoir affected by the EOR project, or an additional 115 million barrels of oil,[12] plus recovery of at least 500 million barrels of natural gas liquids (both additions have been included in the above estimate). Also, the facility establishes a large part of the infrastructure that will be needed to proceed with any future large-scale gas sales or expanded gas cycling projects.[13]

Infill drilling in some portions of the field is continuing at an 80-acre spacing interval; 40-acre spacing is likely to begin soon[14], which may enable recovery of up to 100 million barrels of additional oil. However, infill drilling is probably more important for maintaining or increasing the production rate of fields than for adding reserves. The total number of wells in the Prudhoe Bay field, when fully developed, is expected to be about 1200. Incremental reserves also might be added by expanding the waterflooding operation and/or by expanding the miscible flooding project. Installation of additional gas handling capability would allow greater short-term production levels – since production is constrained by the operator's ability to handle gas produced with the oil—but would not significantly change reserves.

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[11] "World's Biggest Gas Plant Operating on North Slope," Oil and Gas Journal, Jan. 26, 1987, p. 26.

[12] Matthew Berman, Susan Fison, Arlon Tussing, and Samuel Van Vactor, Report on Alaska Benefits and Costs of Exporting Alaska North Slope Crude Oil, for the Alaska State Senate Finance Committee, May 1987, p. A-23.

[13] Alaska Department of Oil and Gas, Division of Oil and Gas, Historical and Projected Oil and Gas Consumption, January 1988, p. 5.

[14] Optimal spacing of wells is determined by balancing expected recovery with the costs to drill additional wells. On the North Slope, 80-acre spacing is typical. In the Lower 48, 40-acre spacing is standard, but even 5-acre spacing is not uncommon.

The West End/Eileen area of Prudhoe Bay is expected to begin producing in 1988 and will include gas injection facilities for pressure maintenance. There are believed to be about 500 million barrels of oil in place in this area, of which about 150 million barrels are considered recoverable. Production from this portion of the Prudhoe Bay field is expected to peak at 60,000 to 70,000 barrels per day.[15]

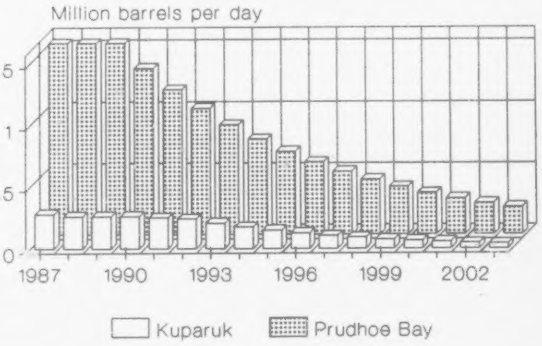
Eventually, more resources also might be recovered in the peripheral area of the Prudhoe Bay field. In the past, operators assumed that production of the Prudhoe oil column was limited to areas where "pay" thicknesses are greater than 100 feet. However, production of the "wedge" zone at the edges of the field using horizontal drilling techniques may yield more oil. This relatively thin zone would not be economic to produce with vertical wells, but horizontal wells allow much more of the formation to be open to the borehole.[16] ARCO notes that development of potential reserves (e.g., Prudhoe Bay's Hurl State and Kuparuk Sand areas, as well as wedge areas) is partially dependent on State severence tax considerations. Under current Alaskan law, oil from marginal fields is taxed at a lower rate than production from more productive fields, thus enabling development of some marginal fields to be economically justified.[17]

Industry and government sources now predict that Prudhoe Bay production will begin to decline in late 1989 or sometime in 1990 (initially the decline was expected sometime in 1987) (Figure 3-3). The actual date will depend on the level of infill development drilling, scheduling of well workovers, water and rich gas injection rates, and the capabilities of the installed and to-be-installed gas handling facilities.[18] Prudhoe's gas-oil and water-oil ratios will continue to increase as its oil is produced. When limits on handling gas and water are reached and additional gas and water injection can no longer be done economically, decline will set in. When the Prudhoe Bay field begins to decline, the rate is expected to be about 10 to 12 percent per year.[19] Such a decline rate is typical of most large oilfields that are subjected to pressure maintenance operations.

Kuparuk River

Production of the Kuparuk River field, located about 40 miles west of Prudhoe Bay, commenced in December 1981. Remaining reserves recoverable with primary and existing waterflood technology were estimated to be slightly over 1 billion barrels as of September 1987. Production, which is now between 290,000 and 300,000 barrels of oil per day, second in the United States only to Prodhoe Bay's, is expected to begin a gradual decline to 65,000 barrels per day in 2000

Figure 3-3.-Alaska North Slope Production: Prudhoe Bay and Kuparuk



SOURCES: Alaska Department of Natural Resources, Division of Oil and Gas and Alaska Department of Revenue, November 1987.

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[15] Matthew Berman, Susan Fison, Arlon Tussing, and Samuel Van Vactor, Report on Alaska Benefits and Costs of Exporting Alaska North Slope Crude Oil, for the Alaska State Senate Finance Committee, May 1987, p. A-24.

[16] J.H. Littleton, "Sohio Studies Extended-Reach Drilling For Prudhoe Bay," Petroleum Engineer International, October 1985, p. 34.

[17] H.P. Foster, Senior Vice President, ARCO Alaska, letter to James Eason, Alaska Department of Natural Resources, Division of Oil and Gas, June 25, 1987.

[18] Alaska Department of Oil and Gas, Division of Oil and Gas, Historical and Projected Oil and Gas Consumption, January 1988, p. 6-7

[19] "Big Prudhoe Bay Field Passes Halfway Mark at 5 Billion BBL," Oil and Gas Journal, Mar. 30, 1987, p. 40.

(Figure 3-3). Although Kuparuk production is expected to fall off less rapidly than production at Prudhoe Bay, it is only about one-fifth of Prudhoe Bay's production and contributes only about 15 percent of TAPS throughput. Remaining recoverable gas is estimated to be about 525 billion cubic feet.

The Kuparuk River reservoir is not as thick or of as high quality as the Prudhoe Bay reservoir. It has no natural gas cap, and is characterized by faulting and discontinuities. The field covers 400 square miles, of which 200 are currently considered commercially productive. By the end of 1986, 300 wells had been drilled, but at least 700 wells will be required for full field development. Constant infill drilling will be necessary to retard decline as long as possible and to tap areas separated by faults.

ARCO Alaska, the operator, is expanding the waterflood program and has recently begun a pilot miscible gas injection project to boost ultimate recovery from the reservoir. A third central production facility was added in 1986, with a reserve addition of 170 million barrels of oil.[20] A small gas plant in the field currently produces about 3,700 barrels per day of natural gas liquids that are blended with the oil and sold.

Lisburne

The Lisburne reservoir lies within the Prudhoe Bay Unit but is about 1,000 feet deeper than Prudhoe Bay's main reservoir in the Ivishak formation. Lisburne and Prudhoe Bay were discovered by the same well. Production from this third largest North Slope field (in terms of estimated reserves) began in December 1986. Thus far, production at the Lisburne reservoir has not been as good as hoped. Lisburne is a naturally fractured carbonate reservoir, less porous than the Sadlerochit main producing formation at Prudhoe Bay. Lisburne's fractured nature has presented some technical production problems. Moreover, at least parts of the formation contain hydrogen sulfide gas which is both corrosive and poisonous.[21] Although the Lisburne field originally had about 3 billion barrels of oil in place, only between 7 percent and 22 percent of in-place resources are expected to be recovered from primary production and with EOR operations planned or in place. The small size of the Lisburne field compared to Prudhoe Bay, as well as lower per well production rates, faster decline in individual well production rates, greater costs associated with greater drilling depths, more difficult rock to drill, presence of hydrogen sulfide gas, etc., make Lisburne somewhat of a marginal North Slope field at current market prices.

Recoverable resources as of January 1988 were estimated by DNR to be between 280 million and 580 million barrels, but operators have noted that, due to the fracturing, it is very difficult to estimate reserves accurately in the Lisburne field without substantial additional drilling. Reserves of this size would be considered substantial in the Lower 48; however, on the North Slope, Lisburne is only marginally economic. Lisburne's early development was helped by its proximity to TAPS and to the infrastructure already in place at Prudhoe Bay. If current lower oil prices had been anticipated, Lisburne might not have been developed when it was. A similar size and type of field 100 miles from the pipeline probably would not be economic to develop at the present time.

Lisburne production was initially expected to peak in the mid-1990s at between 80,000 and 100,000 barrels per day. A revised estimate, which takes into account the difficulties in producing Lisburne, calls for peak production of only 50,000 to 60,000 barrels per day (Figure 3-4).[22] Production of between 45,000 and 60,000 barrels per day is expected to continue through the mid-1990s.

The Lisburne field includes both onshore and offshore areas. Proposed offshore site construction, however, has been canceled. Most of the offshore oil in the Lisburne field can be reached by directional drilling from shore, and ARCO

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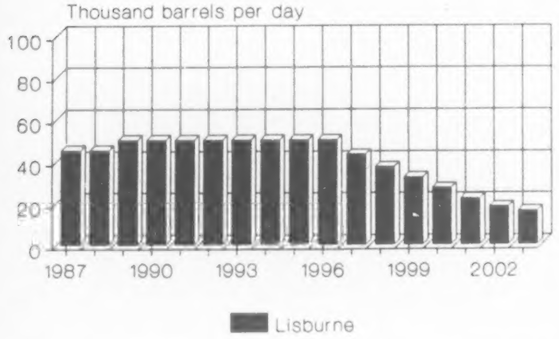
[20] ARCO, Oil Industry Analysts Meeting, New York City, March 31, 1987, p. 13.

[21] M. Harris, "Marginal Fields: Minimizing the Risk," Alaska Construction and Oil, July 1985, p. 15.

[22] Alaska Oil and Gas Conservation Commission, personal communication, December 1987.

Figure 3-4.-Alaska North Slope Production: Lisburne



SOURCES: Alaska Department of Natural Resources, Division of Oil and Gas, November 1987; ARCO Alaska, May 1988.

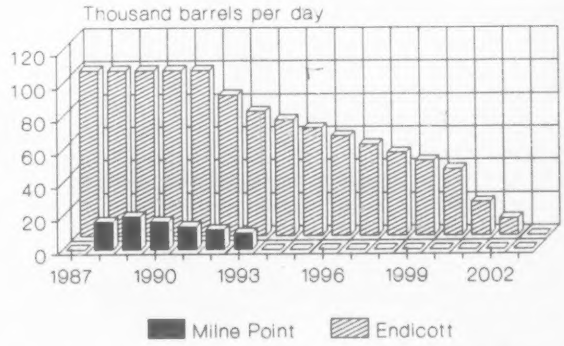
believes it can get to the top of the gas cap—the optimum location for reinjecting gas—by drilling wells with large horizontal offsets from shore. Directional drilling is not expected to reduce oil recovery. A separate geologic structure offshore (the Kuparuk River sand play, productive in the Kuparuk River oilfield and at Niakuk) with an estimated 20 million barrels of reserves is accessible only from an offshore site.[23] Alternatives to exploit this reservoir will have to be developed now that the offshore Lisburne drill site has been canceled. Ultimate recovery at Lisburne is expected to increase if a pilot waterflood project now underway proves to be successful. A small gas plant in the field currently produces about 2,600 barrels per day of natural gas liquids (NGLs), which are blended with the oil and sold.

Endicott

The Endicott field, which began oil production in October 1987, is the North Slope's newest developed field. It is distinctive in that it is the North Slope's first offshore producing field. Located about 15 miles from Prudhoe Bay and about 2 miles offshore in State waters 8 to 10 feet deep, the Endicott field is believed to have about 375 million barrels of oil reserves and 800 billion cubic feet of recoverable gas. Approximately 35 percent of its in-place oil resources are expected to be recovered. Production is from the Kekiktuk conglomerate formation of Mississippian age and takes place from an artificial 45-acre main production island and a 10-acre satellite island. A gravel causeway connects both islands with the shore and provides pipeline and road access.

The Endicott reservoir is similar to Prudhoe Bay's in that it consists of good quality sandstone-conglomerate and contains a large gas cap. The main producing zone has better quality rock than does Prudhoe Bay. The continuity and quality of a second producing zone are still being studied. A significant amount of gas will be produced with Endicott's oil; hence, lack of sufficient gas handling capability could constrain oil production. Production peaked at 115,000 barrels per day in early 1988—equivalent to 5 percent of maximum daily TAPS throughput—and is expected to remain at this level until the field begins to decline, estimated to be some-

Figure 3-5.-Alaska North Slope Production: Endicott and Milne Point



SOURCE: Alaska Department of Natural Resources, Division of Oil and Gas, November 1987.

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[23] "Arco Eyes Production Start at Lisburne During Late 1986," Oil and Gas Journal, August 5, 1985, p. 85.

time in 1992 (Figure 3-5). About 2,500 barrels per day of NGLs are produced at Endicott.

Endicott is also of interest because its development is economic only as a result of intensive efforts to trim the high costs of Arctic construction and drilling.[24] Fields like Endicott are likely to be far more common on the North Slope than Prudhoe Bay-size fields, and close attention will have to be paid to keeping development costs down. Endicott developers were able to build upon experience gained at Prudhoe Bay for example, operators found that retrofitting is very expensive. Thus, primary and secondary recovery capabilities have been part of the production facilities at Endicott from the outset. Hence, waterflood, low pressure separation, gas reinjection, and gas lift can begin at Endicott without substantial additional capital expenditures.

Milne Point

With approximately 60 million barrels of reserves, Milne Point is the smallest of the developed North Slope fields. Production is from the Kuparuk River formation, an extensively faulted sandstone. Milne Point is about 35 miles northwest of Prudhoe Bay. Like Lisburne and Endicott, the proximity of the Trans Alaska Pipeline has spurred development; however, the amount of oil that Milne Point can contribute to TAPS is relatively insignificant. The production target for

Photo credit: American Petroleum Institute

Production facilities at Milne Point. The field is now shut in.

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[24] M.I. Curtis and D.B. Huxley, "First Arctic Offshore Field, Endicott, On Decade-Long Way to Production," Oil and Gas Journal, June 24, 1985, p. 64.

the reservoir is 30,000 barrels per day. If this target is reached, Milne Point will account for 1.5 percent of TAPS throughput during its peak production period. Currently, the peak production capacity is 15,000 barrels per day, or only half the production target (Figure 3-5). Waterflooding has been used since inception, but additional waterflooding and other conventional engineering will be required to produce all of the field's estimated reserves.

Milne Point is the only North Slope field to date that has been shut down due to low oil prices. The field was shut down in January 1987 after a little more than one year in operation. However, it is being maintained in a "warm shutdown" mode so operations can resume quickly if oil prices rise. Conoco, the operator, believes that Milne Point can be economically viable at an oil price of $22 to $25 per barrel.[25]

Milne Point has both onshore and submerged tracts. In addition to the 60 million barrel reserve within the Kuparuk River formation, additional oil may be recoverable using tertiary recovery techniques from the field's shallower Cretaceous sands (identical to the West Sak sands in Kuparuk). However, these shallow sands are loosely cemented and contain viscous oil. Techniques have not yet been worked out to allow the operator to maintain economic flow rates. Closer well spacing will be needed, so the cost of developing these sands will be higher than the cost to develop the main portion of the field.[26]

Proven But Undeveloped Fields

The Alaska Department of Natural Resources has estimated potential reserves for five proven but undeveloped North Slope fields: West Sak, Point Thomson/Flaxman Island, Seal Island/Northstar, Niakuk, and Gwydyr Bay. DNR estimates that production of some West Sak oil might begin at oil prices somewhat below $24 per barrel, but DNR estimates that oil prices will have to rise to at least $24 per barrel before the other three fields will be profitable to develop. Technical innovation may be required in some fields as well.

West Sak, with estimated in-place resources of roughly 15 to 25 billion barrels, is potentially the most important of these fields. Between 2 and 5 percent of these resources are considered recoverable. Approximately 0.5 billion barrels are likely to be recoverable using technology developed from the West Sak pilot project, and 1.5 billion barrels may be recoverable with higher oil prices and using advanced EOR techniques.[27] However, both the amount of oil in place and the ultimate production potential of this marginal field are highly uncertain.[28] Ultimate production potential may be higher than currently estimated. The West Sak field is at a shallow depth, close to an overlying 1,800-foot-thick layer of permafrost, and has a reservoir temperature of about 70°F compared to 195°F for the deeper pay zones in the Prudhoe Bay field. Temperature affects viscosity and the lower temperature West Sak oil is a thick, molasses-like, low-grade crude, which makes it much more difficult to produce than the higher quality, higher temperature oil in the Prudhoe Bay and Endicott reservoirs. The West Sak reservoir is composed of unconsolidated fine-grained sand that tends to flow into the well bore when higher flow rates are attempted.[29] Structurally, West Sak is fairly complex, consisting of multiple faults and "finger" sands. There is large variability in pay zones and fluid properties across the field.

The only long-term production tests to date in West Sak have been in conjunction with a 2-year pilot project. In all, 14 pilot production and injection wells were drilled to a depth of 4,000 feet. Water for the injection wells was heated and injected under high pressure into the formation to increase the temperature of the oil. The flow rate for the test wells was only about 1 percent of the rate for Prudhoe Bay's initial wells—about 200 barrels per day versus up to 20,000 barrels per day at Prudhoe (Prudhoe Bay production averages about 6,000 bpd per well). Because of the reservoir rock and fluid properties, many more wells are likely to be needed than is the case for Prudhoe Bay. Also, the shallow depth of the West Sak reservoir implies that more well pads will be needed than at Prudhoe or Kuparuk since the same horizontal drilling offsets will be difficult to achieve. West Sak acreage drained per well pad will be substantially less (assuming the same number of wells per pad and similar drilling angles and "kickoff" points, a Prudhoe Bay pad would be able to drain 12 times the area as one in West Sak). Thus, a West Sak field would take a long time to develop, and without a breakthrough in recovery technology, is not expected to contribute much to keeping TAPS full. One development scenario envisions five production centers with a total of 5,100 wells (about five times the number of development wells in the Prudhoe Bay field).

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[25] M. Harris, "Oil Industry in Transition," Alaska Construction and Oil, p. 12.

[26] Matthew Berman, Susan Fison, Arlon Tussing, and Samuel Van Vactor, Report on Alaska Benefits and Costs of Exporting Alaska North Slope Crude Oil, for the Alaska State Senate Finance Committee, May 1987, p. A-24.

[27] R.K. Doughty, ARCO Oil and Gas Company, letter to OTA, Jan. 14, 1988.

[28] Berman et al., op. cit., footnote 26.

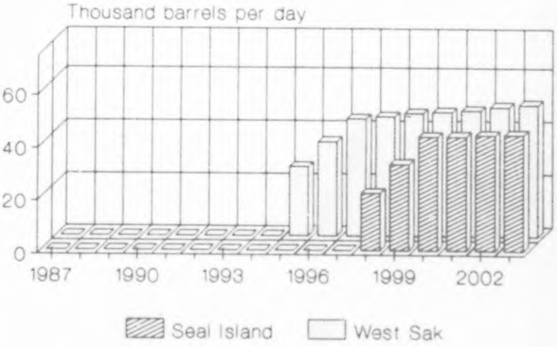
[29] M. Harris, "Marginal Fields: Minimizing the Risk," Alaska Construction and Oil, July 1985, p. 21.

In 1984, ARCO estimated that the West Sak field could be in full production by the late 1980s; however, the company suspended work on the West Sak pilot project in December 1986. ARCO is still evaluating the pilot project results and conducting research on how to develop the field economically. If economic conditions are right, the field could produce about 100,000 barrels of oil per day by 2000 and account for approximately 5 percent of current TAPS capacity. ARCO has shown that the field can be produced using existing technology. However, sophisticated enhanced recovery systems would be required, and these are justifiable only with high oil prices and stable economic conditions.[30] One advantage for West Sak development is that it should be able to capitalize on the extensive facilities already in place for the Kuparuk field; however, full development of West Sak will require the same enclosed production and personnel facilities as Prudhoe Bay but with far less revenue-production potential per dollar invested.[31]

ARCO remains hopeful that it can achieve breakthrough in recovery technology. It plans on beginning a new experimental drilling program in 1989, with up to 25 wells in the pilot program if early wells are successful.[32] If the program is fully successful, ARCO hopes eventually to produce 200,000 to 300,000 bbl/day from the field.[33] Given the substantial technical problems remaining, however, the prospects for West Sak are highly uncertain. Figure III-6 presents a projection of future West Sak production assuming use of available technology.

The Seal Island/Northstar field, being explored by Shell, Amerada Hess, and partners, may be the second offshore field developed. Located approximately 12 miles northwest of Prudhoe Bay, the Seal Island/Northstar field is partially in Alaskan State waters and partially in waters disputed between Alaska and the Federal Government. The disputed leases are managed by the Federal Government. The field is estimated to have in-place resources of approximately 900 million barrels and potential reserves of about

Figure 3-6.-Alaska North Slope Production: West Sak and Seal Island



SOURCE: Alaska Department of Revenue, September 1987.

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[30] M. Harris, "Oil Industry in Transition: Alaska Activity on the Rebound," Alaska Construction and Oil, October 1987, p. 11.

[31] M. Harris, "Marginal Fields: Minimizing the Risk," Alaska Construction and Oil, July 1985, p. 21

[32] T. Bradner, "ARCO Plans West Sak Development," The Energy Daily, December 7, 1988; and personal communication, James Posey, ARCO Alaska, December 12, 1988.

[33] Ibid. This rate of production would be sustained only for a short period, unlike the longer production plateau at Prudhoe. Personal communication, James Mitchell, ARCO Oil and Gas Co., Plano, Texas, December 12, 1988.

300 million barrels. Thus, the field appears to have about the minimum volume of recoverable oil necessary for economic production in the Beaufort Sea given $24 per barrel oil.[34] Seal Island will be considerably more expensive to develop than the Endicott field because it is located 6 miles offshore (4 miles further offshore than Endicott), in 39 feet of water (30 feet deeper than Endicott), and in a floating fast ice zone where moving ice can be a hazard during storms and "breakup." Given the long lead times required for development in the Arctic offshore, production is not expected to begin before the mid-1990s even if prices bounce back up. Higher oil prices and the expectation of continued higher prices will be required to start development and production from the Seal Island and Northstar discoveries. If developed, production could reach 45,000 barrels per day (Figure 3-6) or more. To date, four exploration wells have been drilled on Seal Island and another two on Northstar Island, which is 5 miles west of Seal.

Furthur offshore, Shell and partners announced discovery of oil in early 1986 in the Harvard prospect. The discovery was made from the manmade Sandpiper Island in 49 feet of water. The Harvard prospect is geographically close to Seal and Northstar, and, if enough recoverable oil is present, could be developed concurrently. The Minerals Management Service has termed the find "producible," by which it means there is at least enough oil present to cover daily operating costs of production. The most difficult problem in developing the Seal/Northstar/-Sandpiper area will be constructing the pipeline to shore. Either a buried pipeline or a 5-mile piling-mounted pipeline will be needed, both of which will be very expensive.

The Point Thomson/Flaxman Island field, located on the coast of the Beaufort Sea east of Prudhoe Bay, is estimated to contain about 350 million barrels of recoverable condensate (light gravity hydrocarbons) and approximately 6 trillion cubic feet of recoverable gas. However, development not only awaits higher oil prices but is based on the assumption that a gas cycling project will work that will enable recovery of gas liquids without having to transport and sell the field's gas resources, which is not now economically feasible.[35] The development potential of the Point Thomson field also suffers from its location about 60 miles from the Trans Alaska Pipeline. The outlook for development of this field could improve if a significant oil discovery is made in the Arctic National Wildlife Refuge immediately to the east and a pipeline is built that could also serve Point Thomson.

In December 1987, the Standard Alaska Production Company declared the Niakuk field, located in 4 feet of water 1 mile offshore in State waters immediately northeast of Prudhoe Bay, to be commercial. Standard has estimated reserves to be about 55 million barrels of oil, recoverable using primary and waterflood techniques, and thus the field appears to be in a class with Milne Point and other marginal North Slope fields.[36] The reservoir is the Sag River sandstone, productive at Prudhoe Bay, and separated from Prudhoe by the Niakuk fault system. The field is heavily faulted and divided into at least three discrete pieces, two of which are considered by Standard to be commercial at current oil prices. Standard would like to start producing Niakuk in 1991, contending that this field will be economic to produce, despite its small size, because the field is quite close to Prudhoe Bay, will not require a long offshore causeway or onshore connecting road, will likely be able to use spare production capacity at the Prudhoe Bay and Lisburne fields by the time production begins, and, given its small size, will not require special engineering but will be able to use off-the-shelf facilities. Standard hopes that the field can contribute 20,000 barrels of oil per day to TAPS by the end of 1991.[37]

DNR has estimated potential reserves in the Gwydyr Bay field northeast of Prudhoe Bay – assuming a minimum oil price of $24 – of 10 million barrels. Potential reserves of other small oil discoveries – including Tern Island 35 miles east of Prudhoe Bay, Colville Delta west of the Kuparuk field, Umiat in the National Petroleum Reserve in Alaska (NPRA), and the Hammerhead and Phoenix prospects – and of gas discoveries such as the Kavik and Kemik fields immediately west of ANWR and the East Umiat and Gubik fields in the NPRA have either not yet been determined or not released. There is little to suggest that any of these fields will ever contribute more than small incremental amounts to total North Slope production. Many may never be developed.

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[34] Alaska Department of Natural Resources, Division of Oil and Gas, 1987.

[35] Berman et al., op. cit., footnote 26.

[36] "Alaska Work Hikes Standard Reserves; Niakuk Commercial," Oil and Gas Journal, Dec. 21, 1987. p. 17.

[37] T.Obeney, Niakuk Field Manager, Standard Alaska Production Company, telephone conversation, Jan. 28, 1988.

TECHNOLOGIES FOR IMPROVED RECOVERY

As discussed above, the four largest producing North Slope fields – Prudhoe, Kuparuk, Lisburne, and Endicott – make up all of the present TAPS production and will continue to dominate with at least 80 to 90 percent of all North Slope production well into the 1990s, even with the most optimistic assumption of development for other known fields. With this background, OTA investigated the potential of new advanced recovery technologies either to improve production forecasts for these four fields or to improve production opportunities for other known, but not yet producing, North Slope fields.

To begin this investigation, OTA evaluated future Alaskan North Slope oil production projections and the technological assumptions that affect them. Next, OTA held a workshop[38] to identify current technologies and to project the development of new technologies that could improve production from known Alaskan oilfields. In preparation for the workshop, OTA extracted from published data oil production projections with their accompanying assumptions and assembled brief descriptions of field characteristics. The workshop was focused on the identification of technologies (and their stages of development) that may be used in these fields. OTA asked the workshop participants to review and critique the data assembled and to suggest and discuss technologies from their own knowledge and experience. Participants in the workshop included industry experts in enhanced oil recovery and in North Slope reservoir engineering, as well as researchers from the University of Houston and private independent firms.

The findings of the workshop covered three principal topics: field characteristics that limit recovery; technologies to improve recovery; and projections of future North Slope oil production.

Prudhoe Bay is now and has always been the premier oilfield on the Alaskan North Slope. Not only is it the largest field in the United States, but it is seven to eight times as large (in reserves) as Kuparuk, which ranks number two. Prudhoe is a field with high recovery potential, now estimated at 42 to 45 percent of original oil in place. Prudhoe is the field whose potential fired all North Slope development over a decade ago, and its production is still more than 80 percent of all North Slope oil. Prudhoe is a mature field and is near its peak production.

The other three producing North Slope fields – Kuparuk, Lisburne, and Endicott – now contribute about 15, 2, and 5 percent, respectively, to total North Slope production. The other known North Slope fields – both onshore and offshore – are considered to be of minor importance either because of size (e.g., insignificant portion of TAPS throughput) or because present economics prohibit their development. OTA workshop participants reviewed the information on these other fields and selected one (West Sak) out of the group for discussion. West Sak is a very large field that is not presently economical and that would require significant implementation of enhanced recovery techniques to produce oil. It represents a field with potential but with a range of significant barriers (technical problems) to overcome to reach its potential. The workshop participants therefore focused on technologies that would be applicable to five known North Slope fields – four now producing and one potential.

The oil well recovery systems that are used today are typically described as either primary, secondary, or tertiary. Primary recovery produces the fraction of in-place oil that will flow unaided or can be pumped from the reservoir rock matrix to the surface. Depending on the reservoir characteristics, from 5 to 80 percent of in-place oil may be recovered using primary recovery techniques. In the United States as a whole, average primary recovery has been about 28 percent of in-place oil.[39] In 1979, the American Petroleum Institute reported that the average ultimate recovery of U.S. oil is about 32 percent, with a low of about 14 percent in Ohio and a high of about 65 percent in east Texas. The large, highly permeable reservoirs of east Texas and southern Louisiana have a history of high primary production. Prudhoe Bay is this type of reservoir.

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[38] "North Slope Enhanced Oil Recovery Technologies", Dec. 8, 1987, University of Houston, Houston, Texas.

[39] Todd M. Doscher, "Enhanced Recovery of Crude Oil," American Scientist, April 1981, p. 195.

Secondary recovery techniques are in common use in many reservoirs to increase the percentage of oil recovered. These methods attempt to maintain or restore reservoir pressure by the injection of gas or water (waterflooding). Depending on reservoir conditions and oil properties, secondary recovery techniques can improve in-place oil recovery to between 30 and 50 percent. The injection of water into a reservoir to displace the in-place oil, to reproduce a natural water drive, is the basic secondary recovery operation. In the United States as a whole, waterflooding raises oil recovery efficiency by a factor of 1.5 to 2.0. Waterflooding is dominant among fluid injection methods, and its widespread use is due to the easy availability of water, the relative ease of injection, and the efficiency with which water spreads through a reservoir and displaces oil.

Prudhoe Bay and Kuparuk fields have secondary recovery waterflood operations in place; Endicott is scheduled to start waterflood in 1989 and Lisburne has a waterflood pilot operating. All producing North Slope fields now have applicable secondary recovery techniques in place or planned.

After secondary recovery methods are exhausted, the extraction of additional oil from fields requires the application of more sophisticated and expensive techniques. Enhanced oil recovery processes (or tertiary techniques) can further increase recovery to 40 to 80 percent of the original in-place oil, depending upon the process employed and upon the physical properties of the reservoir and the oil. These techniques usually attempt to reduce oil viscosity and/or to affect other characteristics that impede oil flow. The techniques work by introducing to the producing formation either heat (steam) or substances such as rich miscible gas, carbon dioxide, polymers, solvents, surfactants, micellar fluids, or even microorganisms in various combinations, depending upon reservoir conditions and crude oil properties.

One of these techniques (rich miscible gas injection) is now in place with a major project at Prudhoe Bay and another at Kuparuk. The OTA workshop focused attention on whether a range of enhanced recovery techniques might be applied to the four producing fields and West Sak and, under the most optimistic economic conditions, what improvements in ultimate recovery might be expected.

The OTA workshop reviewed each of the five fields under consideration and noted key features as well as constraints to further production as follows:

Prudhoe Bay (42 to 45 percent recovery)

- Largest light oilfield (27°API, 190°F)
- Dominant and most mature field
- Nearest to decline (1989 or 1990)
- Projects now in place to enhance recovery include:
  - Waterflood
  - Miscible gas injection
  - Infill wells*
  - Horizontal drilling*
  - Other studies by the operators to enhance future recovery include:
  - Adding more natural gas liquids to TAPS
  - Expanding gas handling to increase miscible gas injection
- Reservoir is a thick, high-quality sand with a big gas cap
  - Barriers to increased recovery are limited waterflood contact with oil in the reservoir and gas handling capacity

*These techniques are used primarily to accelerate production rather than to increase ultimate recovery, although some increases are possible, for example, when horizontal drilling is used to reach areas of thin pay not easily drained by regular wells or when infill wells drain portions of oil reservoirs that are not in close connection to the primary network of wells.

Kuparuk (25 to 30 percent recovery)

- Second largest field (27°API, 150°F)
- Compared to Prudhoe, formation is thinner and more spread out with more faults and no gas cap

- The field is constantly on decline without continual infill drilling
- Of 400 square miles, only the inner 200 square miles is commercial
- Waterflood and miscible gas injection projects are now in place
- Barriers to improved recovery include oil saturation, faulting, and relatively thin pay

Lisburne (7 to 22 percent recovery)

- About one-half of this reservoir underlies the main reservoir of the Prudhoe Bay field (27°API, 190°F)
- Very difficult field to produce
- Carbonate reservoir, not well described
- How well oil can be recovered from complex matrix is not yet known; more drilling is needed to better define the reservoir.
- Small waterflood pilot is being tested
- Barriers to improved recovery include low porosity and permeability; fracturing

Endicott (35 percent recovery)

- Similar to Prudhoe reservoir with big gas cap (23°API, 210°F)
- Waterflood designed into the beginning of project for 1989 start-up
- Gas handling may be future problem
- Small field compared to Prudhoe production
- Constrained by faults; reservoir volume well-defined

West Sak (15 to 25 billion barrels estimated oil in place)

- Largest medium-heavy oilfield on North Slope (14 to 22°API, 70°F average)
- Recovery rates are now estimated between 0 and 5 percent by industry, depending on section of the field
- Very difficult field to produce because of poor reservoir conditions, i.e., unconsolidated fine sand and viscous, low-temperature oil
- Early tests indicate well production rates will be very low (hundreds of barrels per day), requiring thousands of wells for any substantial production
- Industry concludes the field is not producible at today's prices

Enhanced recovery techniques possibly applicable to North Slope fields are in three categories: miscible flooding, chemical flooding, and thermal techniques.

Miscible flooding is a technique based upon using some gas – such as enriched reservoir gas (as at Prudhoe) or carbon dioxide (CO_2) or another gas – to miscibly displace some oils, thereby permitting the recovery of most of the in-place oil contacted. The miscible gas is injected into the formation at an injection well and forced toward a production well. A technique for forcing and directing the miscible gas is to alternate water slugs through the same injection well. This is known as Water-Alternating Gas (WAG). A further improvement can be achieved by adding a detergent to the water in WAG which then forms a foam and reduces the apparent viscosity of the fluid. CO_2 gas is more commonly used in the Lower 48 because reservoir gas is a more valuable product. At Prudhoe Bay, gas is not currently marketable and therefore is a more attractive flooding agent.

Chemical flooding is a technique based on adding various chemicals to the water used in waterflooding in order to increase waterflood efficiencies. Chemicals may be polymers, which increase the viscosity of water, surfactants to help release immobilized oil, strong alkalines which themselves form surfactants, or other more complex substances. Foaming agents also have been added to chemical flooding to create a more efficient solution.

Thermal methods involve the injection of steam or hot gas or in-situ combustion – all for production of heavy crude oils whose recovery is impeded by viscous resistance to flow at reservoir temperatures. Foaming agents also can be added to steam to increase steam injection efficiency.

Pressure cycling is the technique of injecting natural gas or CO_2 into the producing formation and alternating high and low injection pressures to induce mixing with the crude and thus stimulating the flow. Lab testing and simulations of "pressure cycling" have been done, and it is believed to be a promising technique for highly fractured reservoirs (such as Lisburne).

Some of these techniques have already been applied (rich miscible gas injection at Prudhoe and Kuparuk) and others have been studied. The list in Table 3-5 covers most of those considered possibly viable by the industry and other researchers at this time. The technique that has provided major improvements for North Slope fields (beyond secondary waterflood) is miscible gas injection. Most others are considered experimental at this stage and almost all must be field tested. A common feature of EOR development is that it is difficult or sometimes impossible to accurately scale up the results of laboratory tests to the field level. Also, some technologies appear impractical for certain North Slope conditions. For example, many thermal processes are difficult to apply because of wide well spacing, depth of the reservoirs, and the substantial permafrost layer.

None of the techniques appear to offer a major increase in recovery rates for the existing North Slope fields. Rather, the dominant industry view is that continued enhanced recovery efforts over a long period of time would likely be able to add a series of small increments to the ultimate recovery percentage for any given field. In general, the industry appears to have greater faith in the gradual accretion of experience from application of existing recovery methods than in the potential of exotic new methods. For Prudhoe Bay this may mean that about 10 percent more oil ultimately will be recovered. For other fields, application of EOR techniques might push recovery rates to the high end of ranges now estimated. In any case, it is not likely that the onset of decline in North Slope production can be delayed more than a few years. The most likely outcome of using more enhanced recovery technology would be to extend field life. This outcome would increase total recovery from certain fields but not necessarily have any immediate effect upon short-term production rates.

Table 3-5.—Some Enhanced Recovery Techniques Possibly Applicable to North Slope Fields

Miscible flooding:	Injecting CO_2[1]
	Injecting Rich Gas[2]
	Water-Alternating-Gas (WAG) to control injectant[2]
	Foam to improve WAG effectiveness[3]
Chemical flooding:	Using—Surfactant Polymers[1]
	—Polymers[1]
	—Alkali[3]
	—Foams to enhance other chemicals[3]
Thermal methods:	Steam Injection[1]
	In-Situ Combustion[3]
	Hot Gas Cycling[4]
	Foam (Steam + Surfactant + Inert Gas)[3]
Pressure cycling:	Using natural gas or CO_2[4]

NOTES: 1. In use in other-Lower 48-fields
2. In use—North Slope
3. Some pilot tests
4. Lab tests and experiments

SOURCE: Office of Technology Assessment, based on Dec. 8, 1987 workshop.

Application of EOR technology is *always* a decision based on economics. Those techniques which the industry considers to be economic under current conditions are being applied in North Slope reservoirs. Higher crude oil prices could result in wider application of current techniques and also increase the chances for economic application of other more speculative technologies.

Table 3-6 shows, for four North Slope fields of interest, the factors for each which may limit production and some applicable enhanced recovery techniques. "Present EOR" denotes work already in place; category A covers techniques that may be applied depending on economic conditions and individual company plans. Category B includes speculative techniques which require development and/or testing and higher oil prices.

Summary

Most of the enhanced recovery techniques that seem practical for North Slope fields today are either in place or already planned for installation in the future. OTA's review did not uncover any technologies that offered major improvements in recovery rates from the fields where we had available information. A careful examination of advanced technologies at the University of Houston workshop led to the summary of possible future enhancements discussed above. The conventional approaches cover most of those in use or planned. More speculative technologies have promise for the future but would certainly require further field testing. OTA was not able to evaluate the economics of EOR but notes that industry claims oil prices must increase before any

Table 3-6.—Problems Limiting North Slope Recovery and Technologies Which May Improve Recovery

Prudhoe Bay	
Limits:	Residual Oil Saturation to Waterflood Actual High Recovery at 42-45% (A good performer as is)
Present EOR:	Waterflood; Miscible Gas Injection; Infill and Horizontal Drilling
A) Conventional Technologies:	Expansion of Waterflood More Miscible Gas Expand Gas Handling Capability (Gas Cycling) More Infill Drilling
B) Speculative Technologies:	Foam to Improve Miscible Gas (Miscible Flood) Surfactant/Polymer (Chemical Flood)
West Sak	
Limits:	Unconsolidated Fine Grained/Sand Production Viscous Oil Poor Rock Quality (shaly)
A) Conventional Technologies: (not economic today)	Waterflood Fracturing
B) Speculative Technologies:	Thermal Methods Miscible Gas or CO_2 (Miscible Flood)
Kuparuk	
Limits:	Basic Residual Oil Saturation Problem Faulted Thin Pay—Especially Outer Edges (half of field area) Absence of a gas cap not a problem since much gas nearby
A) Conventional Technologies:	Waterflood Miscible Gas Infill Drilling
B) Speculative Technologies:	Foam to improve Miscible Gas (Miscible Flood) Polymer (Chemical Flood) Micellar Polymer (Chemical Flood)
Lisburne	
Limits:	Fractured Limestone Low Porosity/Permeability
A) Conventional Technologies:	Waterflood (may be difficult) Infill Drilling
B) Speculative Technologies:	Strategic Infill Drilling Pressure Cycling/Natural Gas

SOURCE: Office of Technology Assessment, based on Dec. 8, 1987 workshop.

techniques beyond ones currently in use are likely to be implemented.

OTA reviewed available current estimates of individual field production rates and ultimate recovery and concluded that the projections in Figures 3-3 through 3-6 are reasonable. In some cases, the data may be either too optimistic or too pessimistic, but, on average, the estimates are as accurate as available information will permit. The total TAPS production estimates in Figure 3-2 seem to adequately bracket the high and low range of future production possibilities.

Future "surprises" at Prudhoe Bay, the dominant field, are unlikely; Prudhoe appears to be the most monitored and computer-modeled field in the world. Furthermore, the operators have foreseen Prudhoe Bay's decline and have been working over a long period of time to keep production high and maximize recovery. There may be, however, a conflict between keeping production high and maximizing ultimate recovery. Some researchers have noted, for example, that increasing the production of natural gas liquids through TAPS, as industry plans to do, may be at the expense of increasing the miscible gas injection project. This could therefore lead to higher production now and lower ultimate recovery. OTA has not investigated the impacts of these details of reservoir management in order to reach an independent conclusion but only notes that choices are not always clear and simple.

The other three fields also do not appear to have many surprises in the offing, and, even if they did, the impact would be minor in relation to TAPS throughput. Kuparuk requires substantial conventional work, such as infill drilling, to keep production up. With waterflood and miscible gas projects in place, the future EOR opportunities that are available are a few of the more exotic chemical flooding techniques. These techniques require further study and testing. Endicott to date is as good a performing field as Prudhoe, and lessons from Prudhoe can best be applied there.

Lisburne is a very difficult field to produce, and disappointing results to date have downgraded its future potential. Some researchers have advocated more experimental technologies to be tried at Lisburne, but this would probably require industry development and testing beyond that justified by today's economics.

The optimistic view of new EOR technologies improving ultimate North Slope recovery appears to be that improvement, if any, will be slow and incremental. Over the next decade the total improvement may be expected to be about 10 percent. Improvements would need to come from advanced techniques that will require testing and capital expenditures beyond what industry claims are presently economically justifiable.

The discovered but still undeveloped fields on the North Slope of Alaska do have the potential to take up some of the slack that will be created when the Prudhoe Bay and Kuparuk fields begin to decline in several years, and application of enhanced oil recovery technologies to known North Slope fields will result in additional reserves. However, neither development of currently undeveloped fields nor the success of EOR projects nor both together is likely to stem the inevitable decline of TAPS thoughput.

OIL PRODUCTION FROM UNDISCOVERED RESOURCES

Alaska's North Slope still contains areas of potential hydrocarbons that the oil industry has never explored or that have received only minimal attention. In prospective offshore areas, for instance, no exploration has yet taken place in the Chukchi Sea, and very little has taken place in the Beaufort Sea adjacent to and north of ANWR. Even the more explored central and western portions of the Beaufort Sea have been barely scratched. Onshore, only one well has been drilled in ANWR, and although a number of unsuccessful wells have been drilled in the National Petroleum Reserve in Alaska, some experts still see the possibility of a commercial discovery in this vast area.

Both the State of Alaska and the Federal Government have scheduled a number of lease sales in the next 5 years. The State plans to hold four offshore and five onshore lease sales on State lands in northern Alaska, while the Federal Government has scheduled two offshore sales in both the Beaufort and Chukchi seas in its most recent 5-year plan (Table 3-7). Discovery of new oil resources on the North Slope could, if large enough and in favorable locations, help keep oil flowing through TAPS. However, a sizable field discovered in 1988 probably would not be producing before 1998, given the long lead times needed to bring a new North Slope field on line.

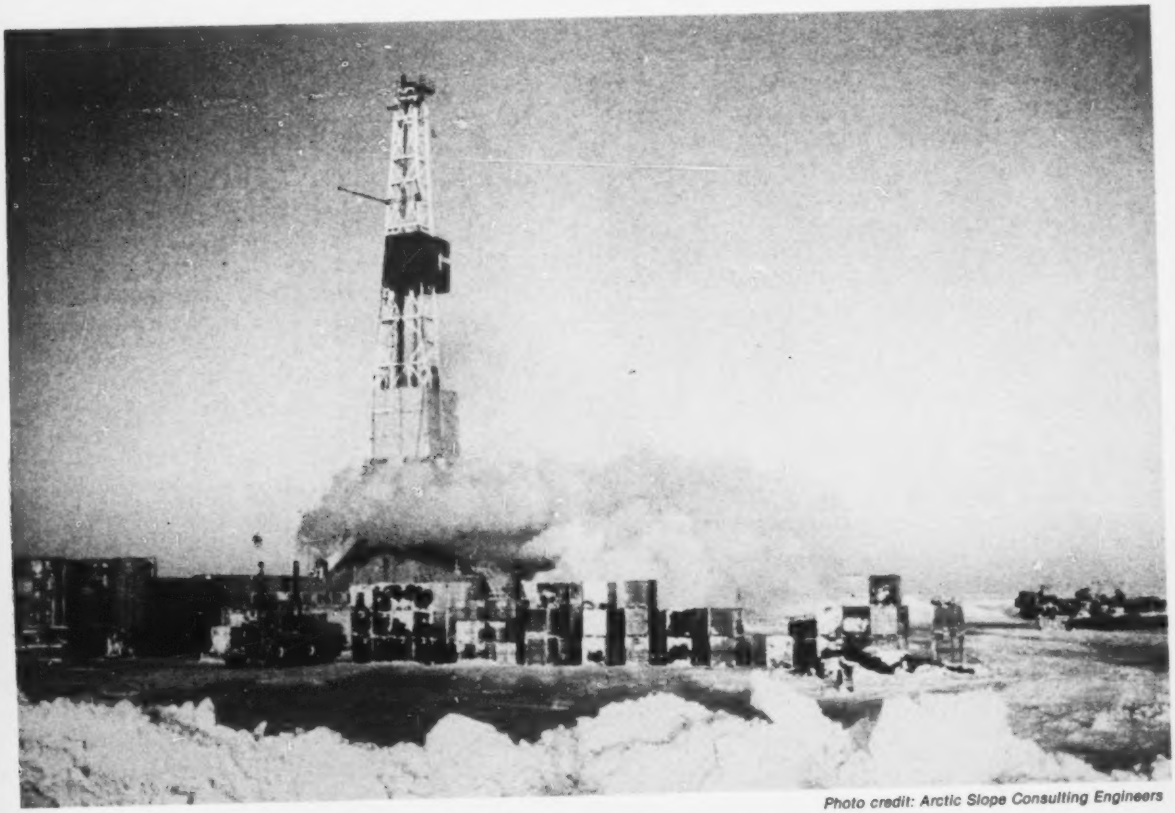

Photo credit: Arctic Slope Consulting Engineers

Chevron's KIC well near Kaktovik is the only onshore exploratory well to probe the oil resources of the ANWR coastal plain. The results are a closely guarded secret.

Table 3-7.—Alaska Lease Sales

Number	Sale	Sale date
A. Proposed Alaska OCS Region Sales		
97	**Beaufort Sea**	**March 1988**
109	**Chukchi Sea**	**May 1988**
107	Navarin Basin	December 1989
101*	St. George Basin	February 1990
114*	Gulf of Ak./Cook Inlet	September 1990
117	N. Aleutian Basin	October 1990
124	**Beaufort Sea**	**February 1991**
126	**Chukchi Sea**	**May 1991**
120*	Norton Basin	September 1989
129*	Shumagin	January 1992
133*	Hope Basin	May 1992
130*	Navarin Basin	January 1992

*To be held only if industry interest warrants.

SOURCE: U.S. Department of the Interior, April 1988.

Number	Sale	Sale date
B. Proposed State of Alaska Sales		
54	**Kuparuk Uplands**	**January 1988**
55	**Demarcation Point**	**June 1988**
66A	**North Slope Exempt**	**June 1988**
52	**Beaufort Sea**	**January 1989**
56	Alaska Peninsula	June 1989
67A	Cook Inlet Exempt	June 1989
59	Cook Inlet	January 1990
57	**North Slope Foothills**	**June 1990**
64	**Kavik**	**January 1991**
65	**Beaufort Sea**	**June 1991**
61	**White Hills**	**January 1992**
68	**Beaufort Sea**	**June 1992**

NOTE: North Slope sales **bold**.

SOURCE: Alaska Department of Natural Resources, Division of Oil and Gas.

Estimates of undiscovered oil may be useful for a number of reasons. These estimates may be used for 1) making long-term energy policy, 2) forecasting rates of domestic discovery and supply, 3) anticipating environmental impacts of exploration and production, 4) making investment decisions, 5) anticipating future technology and capital requirements, 6) realistically evaluating regulatory options, 7) scheduling lease sales, 8) conducting cost-benefit studies of leasing alternatives, and/or 9) analyzing the economics of industry's bids on leasable tracts.[38] Estimates of the undiscovered resources on the North Slope of Alaska are needed for all of these reasons. Several techniques are available for estimating the amount of undiscovered resources a region may contain (see Appendix B). Even with the best techniques available, estimates of undiscovered resources are inherently much more tentative than estimates of resources in known fields.

Estimates for the North Slope

The expectation of the early 1980s that more major oil resources would be found on the North Slope and in other parts of Alaska has not yet been realized. All of the currently producing onshore fields were discovered in the late 1960s, and no significant new discoveries have been made. Offshore areas have been judged by many[39] to be particularly promising, but the only offshore development to date is Standard Alaska Production Company's Endicott field, discovered in 1978. After considerable exploratory drilling, the only noteworthy offshore discovery in the 1980s has been Shell's Seal Island, a field that is not economic to develop at current low oil prices.

While much oil probably remains to be discovered both onshore and in still relatively unexplored offshore areas, it is unlikely that undiscovered resources will be found and developed in time to keep the Trans Alaska Pipeline running at full capacity after 1990. Lead times for development of 15 years or more may be required in some of the more remote places. In any case, new oil discovered in Alaska will not necessarily be found in proximity to TAPS and, hence, may require installation of an alternative transportation infrastructure. Also there has been a slowdown in exploration spending since 1985 because the current price of oil is low.

Several estimates of the undiscovered, economically recoverable resource potential of Alaska have been made. In 1981, the U.S. Geological Survey (USGS) estimated the risked mean of undiscovered, economically recoverable oil offshore Alaska to be 12.2 billion barrels and of natural gas to be 64.6 trillion cubic feet;[40] onshore Alaskan oil and gas resources were estimated to be 6.9 billion barrels of oil and 36.6 trillion cubic feet of natural gas. In 1985, the Minerals Management Service (MMS), which assumed the offshore leasing responsibilities of the Conservation Division of the U.S. Geological Survey in 1982, again estimated offshore undiscovered resources. The newer assessment concluded that Alaskan Outer Continental Shelf (OCS) areas contained 3.3 billion barrels of undiscovered, economically recoverable oil and 13.9 trillion cubic feet of gas. This volume is much lower than the 1981 estimates. MMS assessed only OCS resources (i.e., resources beyond the 3-mile-wide band of State-controlled waters) while the previous USGS estimate considered all offshore resources together. MMS also used a different estimation methodology and revised some of the assumptions used in the earlier USGS estimate. Still, most of the reduction in the estimate of offshore undiscovered, economically recoverable resources probably can be accounted for by the disappointing offshore exploration record between 1981 and 1985 (Table 3-8).[41]

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[38] National Research Council, Offshore Hydrocarbon Resource Estimation: The Minerals Management Service's Methodology (Washington, D.C.: The National Academy Press, 1986), p. 5.

[39] See, for instance, National Petroleum Council, U.S. Arctic Oil and Gas, December 1981.

[40] U.S. Geological Survey, Circular 860, Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States, 1981.

Table 3-8.—Estimates of Undiscovered, Economically Recoverable Oil in Alaska (risked mean billion barrels)

	1981[a]	1985[b]	1988[c]
Offshore			
Beaufort Sea	7.8	0.89	0.21
Navarin Basin	1.0	1.30	0.03
Chukchi Sea	1.6	0.54	0.59
St. George Basin	0.4	0.37	0.01
Norton Basin	0.2	0.09	—
Other	1.2	0.11	0.06
Total Offshore Alaska	12.2	3.30	0.90
Onshore	6.9	—	7.91

[a] 1981 offshore estimates are for oil in both Federal and State waters. The onshore estimate does *not* include oil in State waters.

[b] 1985 offshore estimates are for Federal waters only.

[c] 1988 offshore figures are for Federal waters. The onshore figure is for onshore and State waters. 1988 estimates are preliminary and subject to modification. Totals for onshore and offshore Alaska were not added in the preliminary National Assessment; hence, OTA summed the province numbers to reach the totals in the table.

SOURCES: U.S. Geological Survey, Circular 860, *Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States*, 1981; Minerals Management Service, MMS 85-0012, *Estimates of Undiscovered, Economically Recoverable Oil and Gas Resources for the Outer Continental Shelf as of July 1984*, 1985; U.S. Department of the Interior, *National Assessment of Undiscovered Conventional Oil and Gas Resources*, USGS-MMS Working Paper (Preliminary), Open File Report 88-373, 1988.

In May 1988, the Minerals Management Service and the U.S. Geological Survey released preliminary data from a new study of the Nation's undiscovered oil and gas.[42] The new study incorporates a great deal of new data and uses improved estimation methodologies.[43] The USGS estimated onshore resources and resources in State waters; MMS estimated resources in Federal OCS waters. The new USGS estimate of undiscovered, economically recoverable resources for the total of onshore and State offshore areas of the United States is considerably smaller than the 1981 estimate. The picture for Alaska is less clear. The preliminary 1988 estimate indicates a risked mean of approximately 8 billion barrels of oil in onshore areas and in Alaskan State waters. The corresponding 1981 figure, 6.9 billion barrels, does not differentiate between State and OCS waters, thus making comparisons between the two estimates difficult; however, given the magnitude of USGS's 1981 combined estimate of onshore and shelf offshore oil, a reduced estimate can be inferred.[44]

Alaskan OCS data also have been revised. Preliminary offshore estimates of undiscovered, economically recoverable oil indicate substantially less oil than was estimated in MMS's 1985 estimate. Since 1975, over 90 exploration wells have been drilled in the State and Federal waters of the Beaufort Sea and in the Navarin, Norton, and St. George Basins in the Bering Sea.[45] Few of these exploration wells struck "producible" quantities of oil.[46] Only one offshore discovery, the Endicott reservoir, located in shallow State waters, has been developed to date; only two other likely commercial discoveries have been made, Niakuk and Seal Island. Niakuk is in very shallow State waters adjacent to the existing Prudhoe Bay infrastructure and, hence, may possibly be producing by the early 1990s. Seal Island has been the only OCS discovery to date (although, as noted previously, its OCS status is being disputed by the State of Alaska).

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[41] U.S. Congress Office of Technology Assessment, Oil and Gas Technologies for the Arctic and Deepwater (Washington, DC: U.S. Government Printing Office, 1985), p. 30.

[42] U.S. Department of the Interior, National Assessment of Undiscovered Conventional Oil and Gas Resources, USGS-MMS Working Paper (Preliminary), Open File Report 88-373, 1988.

[43] The play analysis methodology used by USGS and MMS and underlying geologic assumptions will be reviewed before final publication of the report.

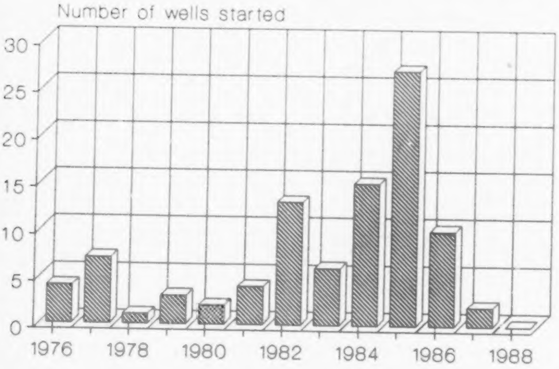
[44] The mean total for onshore oil and shelf offshore oil was estimated in 1981 by USGS to be 17.7 billion barrels. Some of the shelf offshore oil would be expected to be found in State waters.

[45] W.W. Wade, "Exploration and Production in Alaska: A Review and Forecast," World Oil, February 1986, p. 101.

[46] That is, few were determined to be "producible" in accordance with OCS Order No. 4.

The most notable disappointment in OCS exploration was Sohio's Mukluk prospect in the Beaufort Sea. The Mukluk structure was considered the most promising prospect in the Beaufort during 1983, but the failure to discover oil there transformed it into the most costly dry hole in history ($140 million in drilling and island construction costs and over $1 billion in total costs). The Mukluk dry hole figured prominently in the substantial lowering of Beaufort Sea resource estimates in MMS's 1985 reassessment of undiscovered, economically recoverable resources.

Figure 3-7.-Exploratory Wells in the Beaufort and Bering Seas, 1976-88



SOURCE: U.S. Department of the Interior, Minerals Management Service, Alaska/ Summary Index, January 1986-December 1986, pp. 26, 27, 39.

Offshore areas remain relatively unexplored, but the lack of drilling success since 1985 is a major reason for the lower 1988 estimates. Furthermore, low and volatile oil prices have dampened enthusiasm. Exploratory drilling activity has dropped off sharply since the peak year of 1985 (Figure 3-7). Only one well has been drilled thus far in 1988, Tenneco's Aurora well about 4 miles off the coast of the Arctic National Wildlife Refuge, and no others are expected. However, higher and more stable oil prices would likely stimulate higher levels of offshore exploration in the future.

Estimates for ANWR

Although much is said and written about the resource potential of ANWR, it is still a virtually unknown area, and a wide range of resources is possible in ANWR's coastal plain. Much depends, for instance, on the existence and thickness of Ellesmerian sequence rocks in the ANWR area, and State and Federal geologists differ in their assessment of these rocks. Both the State of Alaska and the U.S. Department of the Interior (DOI) have used play analysis to estimate the in-place resource potential of ANWR. The State used a model known as the Resource Appraisal Simulation for Petroleum (RASP) to estimate undiscovered resources there. DOI used a modified version of the play analysis technique developed by the Geological Survey of Canada to estimate ANWR's potential in its mandated report to Congress. The DOI assessment is driven by an efficient computer program known as the Fast Appraisal System for Petroleum (FASP) (see Appendix B for a discussion of these models). Both models use information gained through seismic work and through studies of ANWR's surface geology; both models depend for much of their input on the opinions of geologists familiar with the area; and both models report their results as probability distributions rather than as single point estimates.

The State reports that there is a mean of 7.22 billion barrels of in-place oil in ANWR while DOI reports a mean of 13.8 billion barrels. Given the lack of information about ANWR's subsurface geology, it is not surprising that DOI and State of Alaska estimates differ at all probability levels (Table 3-9).[47] Although the results differ, both studies conclude: a) that the key elements for petroleum accumulations are present beneath the coastal plain of ANWR, b) that there is only a small possibility that unusually large petroleum resources are present, and c) that there is a greater likelihood that resources more moderate in size are present.[48]

One thing is important – much of the difference between the two estimates is due mainly to subjective factors. For instance, DOI and Alaska geologists identified different geological plays for analysis (not unusual given the limited geologic data available), had quite different opinions about the quantity of potentially oil-bearing Ellesmerian sequence rocks in the area, and disagreed about the contribution of pre-Mississippian rocks for oil accumulation.[49] Had the same subjective information been used in each study, the DOI and State estimates using FASP and RASP would have been about the same, but the estimates would not necessarily have been more accurate. Subjective factors necessarily introduce a considerable amount of uncertainty in estimates of undiscovered resources. Drilling data is not available for ANWR's coastal plain.

Table 3-9.—Comparison of Estimates for Undiscovered In-place Oil in ANWR

Probability greater than	State of Alaska RASP	Department of Interior FASP
95%	0.08 BBO[a]	4.8 BBO
75%	1.28	8.2
50%	3.77	11.9
25%	9.18	17.2
5%	26.52	29.4
Mean	7.22	13.8

[a] To be read, "there is a 95% probability the in-place oil resource is greater than .08 billion barrels."

SOURCE: Alaska Department of Natural Resources, "Overview of the Hydrocarbon Potential of the Arctic National Wildlife Refuge Coastal Plain, Alaska," report of investigations 87-7.

The Department of the Interior estimated economically recoverable resources using the PRESTO (Probabilistic Resource Estimates-Offshore) model. With PRESTO, DOI estimated that if at least one field with commercially recoverable quantities of oil is present in ANWR, then there is likely to be a mean of at least 3.23 billion barrels of recoverable oil, a 5 percent probability of at least 9.24 billion barrels, and a 95 percent probability of at *least* 590 million barrels. Note that these estimates are very sensitive to DOI's minimum areawide economic field size, which in turn is dependent on the assumed price of oil (in this case, world oil prices at $35 in the year 2000 in 1984 dollars, with North Slope oil $33 because of market conditions).

The Energy Information Administration (EIA) also estimated the undiscovered, economically recoverable resources of ANWR. EIA assumed that 25 percent of the in-place resources estimated in the DOI study would be recoverable, basing its assumed recovery factor on the approximately 26 percent area-wide recovery factor for known North Slope fields.[50] This assumption results in a base case estimate of 3.45 billion barrels of recoverable oil. If EIA had applied the same recovery factor to the State's in-place estimate, the comparable undiscovered, economically recoverable estimate would be 1.8 billion barrels. OTA has no basis for concluding that one estimate is more accurate than the other, i.e., for using DOI's mean oil in-place figure versus using Alaska's figure.

Note that the EIA and DOI estimates are not as similar as they appear. The DOI estimate depends on the existence of at least one commercial field, and, according to DOI, there is a 19 percent chance that such a field exists in ANWR. The EIA estimate assumes the probability of finding economically recoverable oil is nearly 100 percent (unconditional); EIA reasons that the geologic ingredients are present, that traps exist other than those used by DOI in its PRESTO analysis, and that oil accumulations smaller than 440 million barrels can be economically recovered.

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[47] J.J. Hanson and R.W. Kornbrath, "A Comparison of State and Federal Appraisals of the Arctic National Wildlife Refuge Coastal Plain," Staff paper, Alaska Department of Natural Resources, Division of Mining and Geology, 1987.

[48] Ibid., p. 4.

[49] Ibid., p. 3.

[50] Energy Information Administration, Potential Oil Production From the Coastal Plain of the Arctic National Wildlife Refuge, October 1987.

Various groups support DOI's risked mean estimate of approximately 600 million barrels—that is, 3.23 billion barrels multiplied by the probability of finding economically recoverable oil (19 percent), —as the appropriate measure of ANWR's resource potential. In OTA's view, the more appropriate interpretation of the DOI analysis is that there is an 81 percent chance that no economically recoverable resources will be discovered in ANWR, but if there are any economically recoverable resources at all, there will be a mean of at least 3.23 billion barrels.

On the other hand, if approximately 3.5 billion barrels of recoverable oil are found in ANWR, OTA considers peak production of about 800,000 barrels per day from two producing fields to be reasonable (see OTA scenario— Table 2-4—in Chapter 2). Production that started in 2002 might peak by 2008 and then decline at a rate of about 12 percent per year.

OIL INDUSTRY COST-CUTTING AND THE EFFECT ON OILFIELD DEVELOPMENT

Oilfield costs during the past 15 years have been linked to oil prices. When prices were rising, costs also tended to rise after a short time lag. One reason was that the sellers of equipment and services were able to raise their prices and increase their profit margins when rising prices spurred oilfield activity levels and when the demand for services and equipment outran the supply. Another reason was that rising oil prices tended to dull the incentive for innovative, cost-cutting design and operation. When oil prices began to fall, beginning in 1981, oilfield activity levels dropped, and prices for drilling and other services fell substantially. When oil prices nosedived in late 1985, prices for equipment and services fell along with them. In many areas, for example, day rates for rigs fell more than 50 percent. At the same time, extensive cost-cutting in the industry streamlined oilfield activities so that the actual number of man-days and equipment-days required to complete projects was dramatically down.

For example, the industry drilled about 92,000 wells in 1981 with nearly 4,000 rotary rigs active; 84,000 wells in 1982 with 3,100 rigs active; and 85,000 wells in 1984 with 2,400 rigs.[51] This improvement in "rig efficiency" is a complex function of actual efficiency improvements and other factors, such as changing geographical drilling patterns, shifts in the balance of oil and gas targets, and lower levels of exploration. Unfortunately, it is difficult, if not impossible, to separate out the roles of the various causal factors in the changes in this and other measures of oilfield efficiency.[52] Thus, it is not possible to predict reliably what portion of this increased efficiency would remain if oil prices rebound or other oilfield conditions improve. Nevertheless, OTA believes that there is sufficient evidence to conclude that a significant portion of the measured increases in efficiency represent real increases and are not merely statistical artifacts.

Anecdotal evidence implies that the North Slope has seen considerable cost-cutting success. For example, Standard Alaska Production Company claims to be drilling development wells at Endicott for 40 percent of the originally projected cost—with no reduction in time rates for rigs—and the overall cost for developing the field was about one-third of original projections ($1.3 billion final cost, $3.8 billion conceptual estimate[53]). The majority of the savings came from a combination of additional knowledge of the resource that dictated less expensive requirements and lower material and labor costs because of the general slowdown in oilfield activity—cost reductions that are not likely to be repeatable. A substantial part of the savings, however, resulted from Standard's conscious decision to scale-back and redesign the project. Cost-saving measures included:

- using fewer but larger production modules;
- using self-propelled, cantilevered drilling rigs to allow smaller spacing for wells and to reduce time for well-to-well moves;
- changing the design from one island to two, reducing drilling costs;
- building a gravel causeway rather than undersea pipelines; and
- using a single, rather than a redundant, oil-processing system.[54]

None of these changes are dramatic technological breakthroughs, and all could well have been implemented without the decline in oil prices that began in 1981. However, it seems likely that the price drops were the proximate cause of the process that led to these savings.

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[51] U.S. Congress Office of Technology Assessment, U.S. Oil Production: The Effect of Low Oil Prices - Special Report, OTA-E-348 (Washington, DC: U.S. Government Printing Office, September 1987).

[52] Ibid.

[53] M.I. Curtis and D.B. Huxley, "Endicott Development-Making the Arctic Offshore Economical," Twelfth World Petroleum Congress, Houston, Texas, 1987.

[54] Ibid.

Photo credit: Standard Alaska

Endicott Field, August 1987. Careful redesign allowed substantial cost savings at this field.

The result of these and other cost-cutting successes is that, as oil prices have declined, the "breakeven" oil prices for project development have declined as well. Consequently, projections of reduced activity levels (because of low oil prices) that relied strictly on previous estimates of project costs should be viewed as overly pessimistic. Also, if oil prices rise back to previous levels, much of the "benefit" associated with the period of low prices would remain. For example, the rates for services probably would rise also, but not to previous levels. Higher efficiency reached during the period of low oil prices would probably remain, except for temporary losses that might occur if the demand for oilfield services and equipment outstripped the capacity of the providers. The net result would be that a return to previous oil price levels might find the industry capable of doing more project development than was economic at the time of the previous price peaks.

The oil industry's ability to cut costs in the face of low oil prices implies that projections based on previous cost estimates should be viewed somewhat skeptically. This view applies to production projections for the entire North Slope as well as to estimates of the oil price necessary to develop a 500-million-barrel oilfield in the Arctic National Wildlife Refuge. For the North Slope, the ability of the industry to complete projects at lower costs makes it likely that the more optimistic of the available production projections—forecasting a 25 percent decline in production by 2000—

is the more realistic of the two presented previously. However, basic resource constraints and the unavailability of any "breakthrough" enhanced oil recovery technologies implies that still higher production levels are unlikely. For ANWR, OTA tends to agree with the Energy Information Administration's argument that DOI's estimated Minimum Economic Field Size (MEFS) is probably too large[55] – that a $35/bbl oil price (1984 dollars) would allow the development of a field smaller than DOI's MEFS of 440 million barrels of economically recoverable oil, or else that a 440-million-barrel field could be developed at a price lower than $35/bbl (see Box 3-B).

Photo credit: Standard Alaska

Oil stained rock, Arctic National Wildlife Refuge coastal plain. The Energy Information Administration claims that this and other positive indications of oil potential imply a high probability that commercial quantities of oil can be found in the coastal plain. The Department of the Interior's estimate for the probability of finding commercial quantities of oil on the coastal plain is 19 percent.

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[55] Energy Information Administration, Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge, revised edition, SR/RNGD/87-01, October 1987.

BOX 3-B
HOW MUCH OIL IS IN THE ANWR COASTAL PLAIN?

The decision to allow or block leasing of the ANWR coastal plain depends on balancing the potential damage that exploration and development may cause the wilderness, wildlife, subsistence, and other values with the value of the potential oil resources. Resource estimates for undrilled regions are notoriously subjective and inaccurate, however, and Congress should view the Department of Interior's estimates of ANWR resources as "best guesses" rather than as accurate measurements. Nevertheless, the methods and assumptions used by DOI can be reviewed objectively, and an evaluation can be made of the degree to which the estimates may be conservative or optimistic. OTA has examined DOI's documentation of its economic assessment and reviewed critiques of the assessment. In our view, the assessment is more likely to have produced results that are conservative, that is, results that are more pessimistic about the likely recoverable oil than the evidence suggests. OTA did not review DOI's geologic assessment that produced estimates of total in-place oil, but we note that this assessment is substantially more optimistic than the assessment produced by the State of Alaska. Because the estimate of total recoverable resources reflects both the geologic assessment of in-place resources and the economic assessment of recoverability, OTA is reluctant to conclude that DOI's estimate of total recoverable oil resources in the ANWR coastal plain is either conservative or optimistic. On the other hand, we conclude that DOI's estimate of the likelihood that economically recoverable quantities of oil will be found in ANWR –19 percent at world oil prices of $35/bbl (1984 dollars) – probably is overly pessimistic.

Opponents of development have argued that the DOI estimates of ANWR resources are overly optimistic because DOI assumed unrealistically high world oil prices – $35/bbl (1984 dollars) refinery acquisition costs by the year 2000 with a continued growth in "real" prices beyond 2000 of 1 percent per year.[1] Because the size of the "minimum economic field" – the smallest oilfield that could support the pipeline and other facilities needed to produce and transport ANWR oil – is inversely dependent on oil prices, lowering the assumed prices would tend to increase the minimum field size and thus reduce the estimated probability of finding commercial quantities of oil in ANWR. Lowering the assumed oil price would also affect the estimated volume of recoverable oil. However, the effect appears somewhat perverse because the estimated "mean" volume of oil, assuming that economic amounts are found, actually increases if assumed oil prices are lowered. This counterintuitive effect occurs because reducing the minimum field size adds a number of lower-resource possibilities to the universe of resource possibilities sampled by DOI's probabilistic model. In reality, of course, if economic quantities of oil exist in ANWR, a lower oil price would tend to decrease the volume of oil recovered.

The assumed oil price is only one of several factors that may affect the reliability of the economic assessment. These factors include:

1. **Including or excluding "Sunk Costs."**[2] *In determinating the minimum economic field size (MEFS), the costs of exploration and delineation wells are included in the total costs that must be balanced by the economic value of the oil found.* Assuming that a company purchases a lease and begins exploration, if it then discovers a field it will treat all prior costs – including the costs of exploration – as sunk in determining whether or not to proceed with commercialization. Hence, an oil company may choose to proceed with development even

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[1] J.S. Young and W.S. Hauser, Economics of Oil and Gas Production From ANWR for the Determination of Minimum Economic Field Size, Bureau of Land Management Report PT-87-015-3120-985.

[2] Sunk costs are costs that have already been incurred and cannot be recovered if the project fails.

if the total costs exceed the economic value of the oil. The DOI assumption ignores this possibility.

2. **Including or excluding the possibility of "clusters" of small fields.** *The MEFS is calculated on the basis of its stand-alone prospects. In other words, each prospect is evaluated on the basis of its ability to pay for all of the infrastructure necessary to develop the field, including the main pipeline to TAPS Pump Station #1 in the Prudhoe Bay area.* In reality, two or more fields can share the costs of production facilities, the main pipeline, and other infrastructure costs. Also, offshore development in the Beaufort Sea could share infrastructure costs with onshore fields.[3] Consequently, there is a realistic possibility–ignored by the DOI quantitative analysis–that ANWR oil could be developed even though no single field exceeds the MEFS.

3. **Selection of the assumed tax and royalty system.** *The income taxes paid by a field developer are calculated using the terms of the tax system prior to the 1986 changes in the tax law.* These terms include allowance of investment tax credits, 80 percent expensing of intangible drilling costs, ACRS depreciation for 5-year property for tangible drilling costs, and a 46 percent Federal income tax rate. The industry has claimed that the result of the 1986 changes, on balance, has been to reduce the incentive to find and develop new fields. Thus, using current tax rules might tend to lower the estimated oil potential in ANWR.

4. **Assumed oilfield costs**. The estimated costs of drilling, building the pipeline, and other necessary construction and operations are based on the 1981 National Petroleum Council report on Arctic oil and gas,[4] supplemented with other data. According to industry reports, experience of the past few years–especially following the severe oil price drop of 1985/86–has demonstrated that the costs of Arctic operations can be reduced significantly. For example, both ARCO and the Standard Alaska Production Company claim to have reduced development drilling costs sharply by increasing drilling efficiency. Thus, there is a strong possibility that the DOI cost data overstates the likely costs for ANWR field development and depresses the estimated oil potential.

5. **Assumed oil prices**. In its base case, DOI assumed that world oil prices would rise to $35/bbl in 1984 dollars by 2000 and would then rise in real terms by 1 percent per year thereafter. DOI's analysis clearly demonstrates that the estimates of MEFS–and thus the likely resource value–are highly sensitive to the assumed oil price. For example, for a field in the western portion of ANWR, MEFS is 425 million bbl at a $35/bbl oil price and 1.39 billion bbl for a $22/bbl oil price.[5] Although DOI's price assumptions have been severely criticized, OTA believes that oil prices could attain this level if current forecasts of future world oil demand and supply trends prove to be correct. There are, however, plausible circumstances that would maintain prices significantly below this level. In OTA's view, the range of plausible year 2000 oil prices is wide–probably at least from $22 to $40 per barrel in 1987 dollars–and there is no way to select a "most likely" price that could achieve any kind of consensus.

6. **Inclusion or exclusion of geologic targets**. *The DOI recoverable resource analysis is restricted to the 26 largest structural prospects identified by the initial geophysical surveys of the area.* As noted in DOI's ANWR Resource Assessment,[6] additional amounts of economically recoverable oil may be present in smaller structural traps and in so-called stratigraphic traps

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[3] These factors are discussed in the Department of the Interior, Arctic National Wildlife Refuge, Alaska, Coastal Plain Resource Assessment, April 1987.

[4] National Petroleum Council, U.S. Arctic Oil and Gas, December 1981.

[5] Young and Hauser, op.cit., Box 3-B, footnote 1.

[6] U.S. Department of the Interior, Arctic National Wildlife Refuge, Alaska, Coastal Plain Resource Assessment, April 1987.

that were not identified by the available geophysical information. Including these additional prospects should increase the estimated values of both the probability of finding economically recoverable oil in ANWR and the mean recoverable resource.

The first, second, fourth, and sixth factors tend to understate the likely oil potential in ANWR; the third tends to overstate it; and the fifth gives no clear direction. **Overall, OTA believes that DOI's economic evaluation of ANWR oil potential is likely to be too pessimistic, especially with regard to the probability of finding a field of commercial size.**

The DOI assessment of ANWR's oil potential is dependent on both the economic and geologic assessments, however. The geologic assessment prepared by the State of Alaska is more pessimistic than DOI's geologic assessment. For example, the State estimated the "50th percentile" in-place resource to be 3.77 billion barrels (that is, there is a 50 percent chance that there are at least 3.77 billion barrels of in-place resources) versus DOI's estimate of 11.9 billion. The primary factors causing the disagreement are sharply differing views of the likelihood of finding large volumes of oil-bearing Ellesmerian rocks in the coastal plain (the State largely discounts the role of the Ellesmerian) and differing estimates of success rates for individual wells (the State expects lower success rates than does DOI). Given the judgmental character of the estimates and the lack of drilling data, this level of disagreement is not at all unusual. However, the State's estimates would imply a much lower resource value for the ANWR coastal plain than the value assigned by DOI.

The Energy Information Administration (EIA) also has examined the DOI assessment of economically recoverable oil in the coastal plain. EIA concluded that DOI's assessment of in-place resources was reasonable, but it disagreed strongly with DOI's evaluation of the risk of finding economically recoverable oil and also disagreed with DOI's assessment of the likely magnitude of any recoverable resources. In particular, **EIA rejected DOI's estimate that there is only a 19 percent probability of finding oil in economically recoverable quantities; instead, EIA concluded that the probability of finding economically recoverable oil in ANWR is very high. EIA projects the likely economically recoverable oil in ANWR (at DOI's assumed oil prices) to be 3.4 billion barrels, with little likelihood (compared to DOI's 81 percent likelihood) that nothing will be recovered.** OTA generally agrees with EIA's qualitative assessment of DOI's economic evaluation. We note, however, that EIA's alternative methodology for estimating ANWR recoverable resources is unsophisticated, relying on a simple extrapolation of the recovery rates of known North Slope fields. On the other hand, given the limited data on ANWR, EIA's simple approach may prove just as accurate as the more detailed approach of DOI.

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7. Energy Information Administration, Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge, revised edition, SR/RNGD/87-01. In its report, EIA arrived at essentially the same qualitative conclusions about the details of DOI's economic analylis as OTA did and has discussed them in more detail.

Appendixes

Appendix A
Methods of Estimating Discovered In-Place Resources and Reserves

An estimate is only as good as the quality and quantity of the data available at the time it is made. Estimating either in-place resources, recoverable resources, or reserves is inherently difficult because petroleum engineers cannot see the reservoir. Typically they must rely on indirect measurements (e.g., from well logs and cores, seismic work, regional geology, etc.) that supply them with only a partial picture about the shape and characteristics of the reservoir. As more data become available through exploratory drilling, development drilling, and production, early estimates can be refined. Reserve estimates often grow with time. For instance, accumulated initial domestic reserve estimates have averaged about 50 percent of final estimates. Also, there is a tendency to overestimate small discoveries and to underestimate large ones[1] (estimates of Prudhoe Bay's reserves have indeed grown over time, but estimates of original reserves (i.e., of ultimate recovery) appear to be converging on 12 billion barrels).

Several methods are available for estimating in-place resources. The volumetric method, for instance, is one of the simplest ways of calculating in-place resources and is useful when not much data are available. In the volumetric method, seismic and drilling information are used to determine the structure, areal extent, and thickness of potential reservoir rocks. A rough estimate of the bulk rock volume of the reservoir can then be made. In addition, estimates are made of the average porosity and water saturation of the reservoir and of oil and gas volume factors related to the reservoir's pressure and temperature. Knowledge of the porosity—a measure of the amount of void or pore space in a rock—enables the reservoir engineer to estimate the amount of fluids the reservoir is capable of holding. Knowledge of average water saturation within the pore spaces allows engineers to determine how much of the pore space is not occupied by water and could contain oil and/or gas. Once estimates of bulk volume, average porosity, water saturation, and oil/gas volume factors have been obtained, a calculation of the in-place resource can be made.

Estimates made using the volumetric method may vary widely depending on the amount of information available. If data are derived from only a few wells or from the results of pre-drilling surveys, the best one can do is assume uniform thickness, porosity, and water saturation for various segments of a reservoir. In reality, reservoirs are usually complex: for example, thickness, porosity, and water saturation may all vary considerably; faulting introduces barriers to flow, as do low permeability zones; and oil and gas within the gross reservoir may be in unconnected compartments. Hence, if the geological interpretation is not correct or not sufficiently precise, the result of gross volumetric calculations will be wrong.

A second technique sometimes used to obtain estimates of in-place resources (and reserves as well) is the material balance method. A material balance calculation relies on the assumption that a petroleum reservoir can function as a large closed tank containing oil, gas, and water. By measuring the change in pressure after various known increments of production, it is possible to calculate the original in-place amounts of oil, gas, and water.[2] A principal weakness of this method is that reservoirs are treated as a single unit under constant pressure. Typically, however, pressure will vary considerably throughout a reservoir. Treating the reservoir as an undifferentiated unit, therefore, may not adequately model the reservoir.

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[1] Riva, op. cit., p. 126.

[2] Riva, op. cit., p. 125.

Several techniques are also used for estimating recoverable oil and gas. A rough estimate of recovery can be made using the analogy method. For this technique, one can simply apply a recovery factor to in-place resources. A recovery factor is the percentage of in-place resources that are expected to be recoverable in a reservoir, and the factor used to estimate recoverable volumes from a given reservoir is one associated with another reservoir having a recovery factor known from production history and characteristics similar to the one being investigated.

A second recoverable resource estimation technique is decline curve analysis. Peak production must already have taken place to properly use this technique. From a study of the production trend over time, a mathematical relationship can be established. Using this relationship, one can then project production into the future to the point where further production would no longer be economically feasible. The total production over time constitutes the ultimately recoverable oil and gas. A weakness in the decline curve method is that it is only indicative if wells are allowed to produce at their maximum (unrestricted) rate. If the flow rate is restricted, either by company policy or State or Federal regulations, the decline curve will show a downward trend in time that will not truly reflect recoverable oil and gas.[3]

The most sophisticated technique used to estimate recoverable oil and gas is reservoir simulation. In setting up a simulator, all available information on reservoir and fluid characteristics is used. Unlike the material balance method in which the reservoir is considered to function as a single tank, reservoir simulation more systematically considers the reservoir as an aggregate of many cells, each with its own parametric values, such as fluid saturations, permeabilities, pressures, etc. Using all the data, flow equations are developed for a reservoir which match the reservoir's history. These equations are then solved, using computer processing, to estimate recoverable resources. Typically, reservoir simulators are quite expensive to develop and are developed only for the largest fields. The Prudhoe Bay field, the country's largest, has been simulated using the best available methods.

All estimation techniques have their shortcomings. Specifically, one must always keep in mind that 1) although estimates may make use of the best available data, the availability and quality of data for oil and gas estimates are often limited, and 2) the estimate is usually based on a number of simplifying assumptions about the reservoir characteristics and/or future trends in price and technology development.

In addition to the inherent difficulty of making accurate resource and reserve estimates, data access problems hamper the accuracy, or at least the credibility, of published estimates. Published reserve estimates made by such agencies as the Alaska Oil and Gas Conservation Commission; the Alaska Department of Natural Resources, Division of Oil and Gas; and the U.S. Department of Energy's Energy Information Administration all ultimately rely on data supplied by the oil and gas industry. Although some oil company data must by law be released to these and other State and Federal agencies which make estimates and regulate the oil industry, much industry data is proprietary. Estimates that the oil companies themselves make are generally not publicly available. Moreover, oil companies usually are not willing to be too precise about estimates they do release. Typically, a company will confirm that recoverable resources, for example, are likely within a specified range, but they are reluctant to go further. Hence, public estimates, even if in the same range as the industry's estimates, are usually not based on all the information to which the oil companies have access.

The oil and gas business is competitive, and proprietary knowledge represents an advantage. Among the reasons for industry's desire to keep information proprietary are that: 1) a competitor with precise knowledge of a company's reserves estimate could gain an advantage in future lease sales in the area; 2) estimates, even by the companies themselves, are at best only approximate; hence, publication of a reserve estimate that later turned out to represent falsely company assets

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3. Robert Hubbell, reservoir engineer, Golden Engineering, personal communication, Dec. 23, 1987.

could significantly affect investors or potential investors; and 3) a company's oil and gas reserves can be the object of hostile takeover attempts.

An additional caveat in comparing estimates made by different groups (particularly of reserves or recoverable resources) is that the assumptions on which each estimate is based may not be – in fact, usually are not – made explicit. Such assumptions usually include the projected price of oil, the amount of capital investment planned for the field, and the type of secondary or enhanced oil recovery techniques expected to be used. Also, it is sometimes difficult to determine which portion of a reported reserves estimate is proved and which is only inferred or potential (some North Slope estimates include both proved and potential reserves). This greatly complicates attempts to compare alternative estimates of reserves. Also, unless all reserve estimates are accounted to the same time for a specific field or group of fields, estimate comparisons will not be valid.

Appendix B
Estimation Methods for Undiscovered Resources

The purpose of any resource estimate is to produce the best possible guess about the extent of resources in the absence of data which would allow one to calculate a more precise figure. Reasonably accurate data about oil and gas resources can only be generated through extensive drilling; however, geological and geophysical information prior to extensive drilling and preliminary exploratory drilling at a later stage does provide information which can be used for gaining some insight into the amount of resources in an area. This information can be used to estimate resources. Methods have been developed to estimate both undiscovered, in-place resources and economically recoverable resources. Geological factors are the main consideration in estimating in-place resources; estimates of economically recoverable oil and gas must take into account various economic and technological factors and regulatory policy as well.

Although methods for estimating resources have become sophisticated, estimates are only as good as the data used to produce them. An estimate may represent the best appraisal that can be made at the time, but only by the greatest of luck will the amount of resources eventually found in an area be similar to the amount originally estimated. As relevant today as in 1934 is J.T. Hayward's remark, "...we must not fall into the error of believing that because we have attached a number to a chance that we have thereby made a successful issue more sure, or have in any way altered its probability. Further, we must be ever on the watch for that most insidious and widespread superstition that assumes that mathematical manipulation, if sufficiently accurate, involved, and prolonged can transmute doubtful data into positive scientific fact."[1]

In a recent study of hydrocarbon estimation techniques the National Research Council pointed out that the quality of an estimate of undiscovered resources is highly dependent upon: 1) the quantity and quality of the geologic information available; 2) the knowledge, experience, and awareness of the group making the estimate; 3) the appropriateness of the estimation methodology; and 4) (for estimates of economically recoverable resources), the economic assumptions used. Moreover, they noted that users of any resource estimate must recognize its probabilistic nature and resulting inherent uncertainty.[2]

The variability between estimates made by different people using the same method (as well as between estimates made using different techniques) can also be wide. This is so because each model calls for a number of subjective inputs. For example, many models depend in one way or another on the use of geologic analogy. Differences of opinion easily can exist over what geologic analogy is most appropriate. When little information is available, structural geology and stratigraphy can and are interpreted differently. For example, in evaluating the resource potential of the Arctic National Wildlife Refuge, geologists from the State of Alaska and from the Department of the Interior used similar play analysis methods; however, they identified the plays differently.

A number of methodologies have been devised to help estimate, with limited data, the expected amount of resources in an area. Some of the methods are fairly crude; others are quite sophisticated, although again it must be stressed that even the most sophisticated methods produce only estimates, and many of these estimates require numerous assumptions and much subjective input. Five basic types of assessment methods are currently in use. These include:

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[1] J.T. Hayward, "Probabilities and Wildcats Tested Through Mathematical Manipulation," Oil and Gas Journal, vol. 33, No. 26, Nov. 15, 1934, pp. 129-131.

[2] National Research Council, Offshore Hydrocarbon Resource Estimation, p. 7.

1. Areal and volumetric yield methods in combination with geologic analogy. These techniques range from worldwide average yields applied uniformly over a sedimentary basin to more sophisticated analyses in which the yields from a geologically analogous basin are used to provide a basis of comparison.
2. Delphi or subjective consensus methods. In this approach, the estimation of petroleum resources is the consensus of a team of experts who review all the geologic information available in an area or basin.
3. Historical performance or behavioristic methods. These methods are based on extrapolating historical data, such as discovery rates, drilling rates, productivity rates, and known field size distributions.
4. Geochemical material balance methods. These methods are used to estimate how much oil or gas was generated in source rocks of a given area, how much was involved in migration, probable losses during migration, and the quantity that accumulated in deposits.
5. Integrated methods. These methods use a combination of some or all of the above and incorporate geological and statistical models.[3]

The integrated methods, such as play and prospect analyses, are the most sophisticated. Play analysis methods have become popular in recent years for assessing conventional petroleum resources in identified or conceptual exploration plays in a basin or province.[4] These methods produce a range of estimates related to the probability of occurrence of certain amounts of oil rather than a single estimate of resources expected in one or more plays. Since much effort has been expended by State and Federal resource agencies applying these methods to estimating the resources of both the National Petroleum Reserve in Alaska and the Arctic National Wildlife Refuge, these methods and the assumptions that go into them will be described in greater detail.

In-Place Resource Models: RASP and FASP

In-place oil and gas resources include all categories of resources still in the ground, that is, those that are considered to be economically recoverable, those that are technically but not economically recoverable, and those that cannot yet be technically or economically recovered. In-place resources, usually expressed in terms of original in-place volumes, constitute the resource base. Roughly 10 percent to at most 50 percent of in-place oil resources in any given resource area can typically be economically recovered using currently available technology and techniques. Estimates of in-place resources depend upon the interpretation of the geology, economic factors being irrevelant.

Play and prospect analysis models for assessing in-place resources include the Resource Appraisal Simulation for Petroleum (RASP) and the Fast Appraisal System for Petroleum (FASP). RASP has been used by the U.S. Geological Survey to assess resources in both the National Petroleum Reserve in Alaska (1979) and in the

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[3] Betty M. Miller, "Resource Appraisal Methods: Choice and Outcome," in Oil and Gas Assessment—Methods and Applications, AAPG Studies in Geology #21, Dudley D. Rice (ed.) (Tulsa, OK: American Association of Petroleum Geologists, 1986), pp. 2-5.

[4] Ibid., pp. 4-5.

Arctic National Wildlife Refuge (1980).[5] More recently (1986) the State of Alaska used the RASP methodology to estimate resources in ANWR.[6] And the newer FASP method, which is more efficient but produces similar estimates, was used by the Department of the Interior in 1986 to estimate in-place resources in ANWR.[7]

Both methods are based upon the same geologic model and employ the same probability assumptions.[8] However, RASP employs a Monte Carlo simulation technique which typically requires 3000 to 5000 repetitions while FASP is an analytic method which uses statistical techniques and probability theory rather than simulation and thereby greatly speeds up and reduces the cost of the estimation process.

Both methods make extensive use of the judgment of geologists familiar with the geology of the area. In undrilled areas, geologists must depend on surface geology and geophysical data and consider possible geologic analogies with other areas when they make their appraisals. For each identified play (group of geologically related prospects with similar hydrocarbon sources, reservoirs, and traps) within an assessment area, RASP and FASP require that geologists judge the probability that a hydrocarbon source exists, that the timing of oil formation has been favorable, that oil migration from source to traps has been successful, and that the trap contains reservoir grade rock. The product of these four regional geological characteristics (assuming the probability of each occurring is independent of the others' occurrence) jointly determines the marginal probability—the probability that the play contains hydrocarbon accumulations.

Expert judgment is likewise called for at the level of individual prospects, the untested geologic features having the potential for trapping and accumulating hydrocarbons. The prospect attributes are the geologic characteristics common to the individual prospects within a play. Geologists must assess the probability of the existence of a trapping mechanism for the prospects, the likelihood that effective porosity exceeds a certain amount, and the probability that oil and gas exist in at least 1 percent of a trap. The product of these probabilities (again assuming independence) is the probability that a prospect is a deposit, but it is conditional upon the favorability of the play. Together the marginal play probability and the conditional deposit probability are the risk factors. If all attributes comprising these risk factors are favorable, it is likely that there will be hydrocarbons in at least some of the prospects within the play.

A third set of judgments is needed to determine *how much* oil may be contained in each prospect. Geologists are asked to estimate the range of possible values for each of five volume attributes (area of closure, reservoir thickness, effective porosity, trap fill, and reservoir depth) and to assign the probability of a given value to one of seven categories. For example, a geologist may estimate that there is a 100 percent probability that the reservoir thickness of a deposit is greater than or equal to 50 feet, a 75 percent probability that the thickness is greater than 80 feet, and a 25 percent probability that the thickness is greater than 100 feet. From these estimates, a probability distribution for each of the volume attributes can be made. A range of values is also estimated for the number of drillable prospects in each play. And finally, geologists are asked to as-

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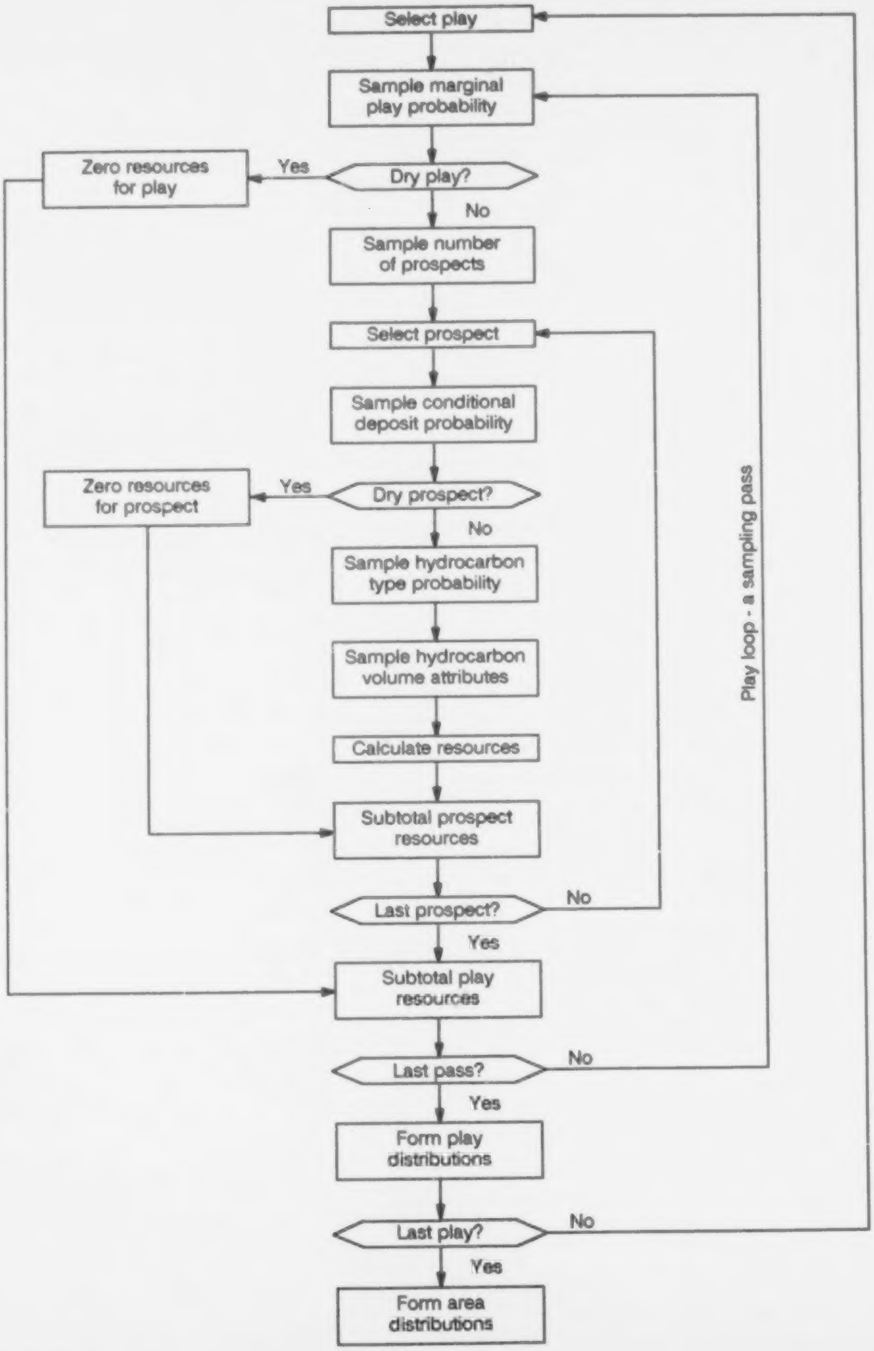
[5] Kenneth J. Bird, "A Comparison of the Play Analysis Technique as Applied in Hydrocarbon Resource Assessments of the National Petroleum Reserve in Alaska and the Arctic National Wildlike Refuge," in Oil and Gas Assessment – Methods and Applications, Dudley D. Rice (Tulsa, OK: American Association of Petroleum Geologists, 1986), pp. 133-142.

[6] J.J. Hansen and R.W. Kornbrath, "Resource Appraisal Simulation for Petroleum in the Arctic National Wildlife Refuge, Alaska," Professional Report 90 (State of Alaska: Department of Natural Resources, 1986), pp. 1-13.

[7] U.S. Department of the Interior, Arctic National Wildlife Refuge, Alaska, Coastal Plain Resource Assessment (Washington, DC: U.S. Fish and Wildlife Service, U.S. Geological Survey, and Bureau of Land Management, 1987). See chapter III, "Assessment of Oil and Gas Potential and Petroleum Geology of the 1002 Area," pp. 55-81.

[8] Robert A. Crovelli, "An Analytic Probabilistic Methodology for Resource Appraisal of Undiscovered Oil and Gas Resources in Play Analysis," U.S. Geological Survey Open File Report 85-657, 1985.

Figure B-1.—Flow Chart of Simulation Method for Play Analysis



Select play
Sample marginal play probability
Zero resources for play
Yes
Dry play?
No
Sample number of prospects
Select prospect
Sample conditional deposit probability
Zero resources for prospect
Yes
Dry prospect?
No
Sample hydrocarbon type probability
Sample hydrocarbon volume attributes
Calculate resources
Subtotal prospect resources
Last prospect?
No
Yes
Subtotal play resources
Last pass?
No
Yes
Form play distributions
Last play?
No
Yes
Form area distributions
Play loop - a sampling pass

SOURCE: Robert A. Crovelli, "A Comparison of Analytic and Simulation Methods for Petroleum Play Analysis and Aggregation." U.S. Geological Survey Open-File Report 86-97. 1986.

sess the likely reservoir characteristics and hydrocarbon mix.

If RASP is used, a simulation is run using the probabilities estimated in the geologic model (figure B-1). First, the marginal play probability is sampled. If the sampled play is "dry," zero resources are assigned to that play on that pass. If the play is not dry, the number of prospects in the play are sampled. Then each of the prospects in the play are examined in turn. Sampling the conditional deposit probability for each prospect determines whether the prospect is dry or contains oil and/or gas. If hydrocarbons are simulated as present, each of the hydrocarbon volume attributes are sampled, and the resources within the prospect are calculated using standard reservoir engineering equations. After the last prospect within the play is sampled, the resources are totaled for that play, and the simulation proceeds to the next play. The process is repeated until all the plays have been examined. The resource estimates for all the plays are summed to obtain the total amount of simulated oil in the assessment area. The simulation is then rerun as many as 5,000 times. Probability distributions can then be derived by ranking results for each pass and dividing the rank ordering into fractiles.[9]

The simulation method is easier to understand than the analytic method, but the outcomes are much the same. In the FASP analytic method, the simulation is replaced by a statistical procedure which calculates means and variances of the same geologic variables to derive an estimate for one play (figure B-2). Results for individual plays are then aggregated using the aggregation model FASPA. Comparisons of RASP and FASP have been made, and results show excellent agreement.[10] The analytic method, however, has some advantages. A principle one is that it is thousands of times faster. The cost to run the program is therefore negligible and FASP can be rerun frequently, incorporating new data as available. The analytic method is also potentially more useful because it produces mathematical equations of probabilistic relationships involving petroleum resources.

Estimating Economically Recoverable Undiscovered Resources: PRESTO

Models have also been developed to estimate the amount of undiscovered but economically recoverable resources in a given area. In particular, the Minerals Management Service's PRESTO (**P**robabilistic **R**esource **Est**imates-**O**ffshore) model (now in its third version) has been used to estimate undiscovered, economically recoverable resources in arctic offshore areas and, recently, in the Arctic National Wildlife Refuge. Conceptually, the model has much in common with RASP, in that it incorporates Monte Carlo simulation, ranges of values for volumetric input parameters, and risk analysis.[11] The most important unit of analysis used to derive PRESTO estimates is the prospect, or individual potential oil or gas field. As in RASP, marginal and conditional risks are determined. The marginal basin risk is the probability that no prospect within a given basin contains hydrocarbons; the conditional prospect risk is the probability that an individual prospect modelled is "dry," conditional upon the basin containing at least some economically recoverable hydrocarbons. These risks are determined by geologists using all available geological and geophysical data. Needless to say, in undrilled and largely unexplored areas, the data are usually scanty. Moreover, PRESTO, like other resource estimation models, uses the judgment of experts when "hard" data are unavailable. Identification and characterization of prospects, for instance, calls for significant subjective input in the absence of substantial drilling.

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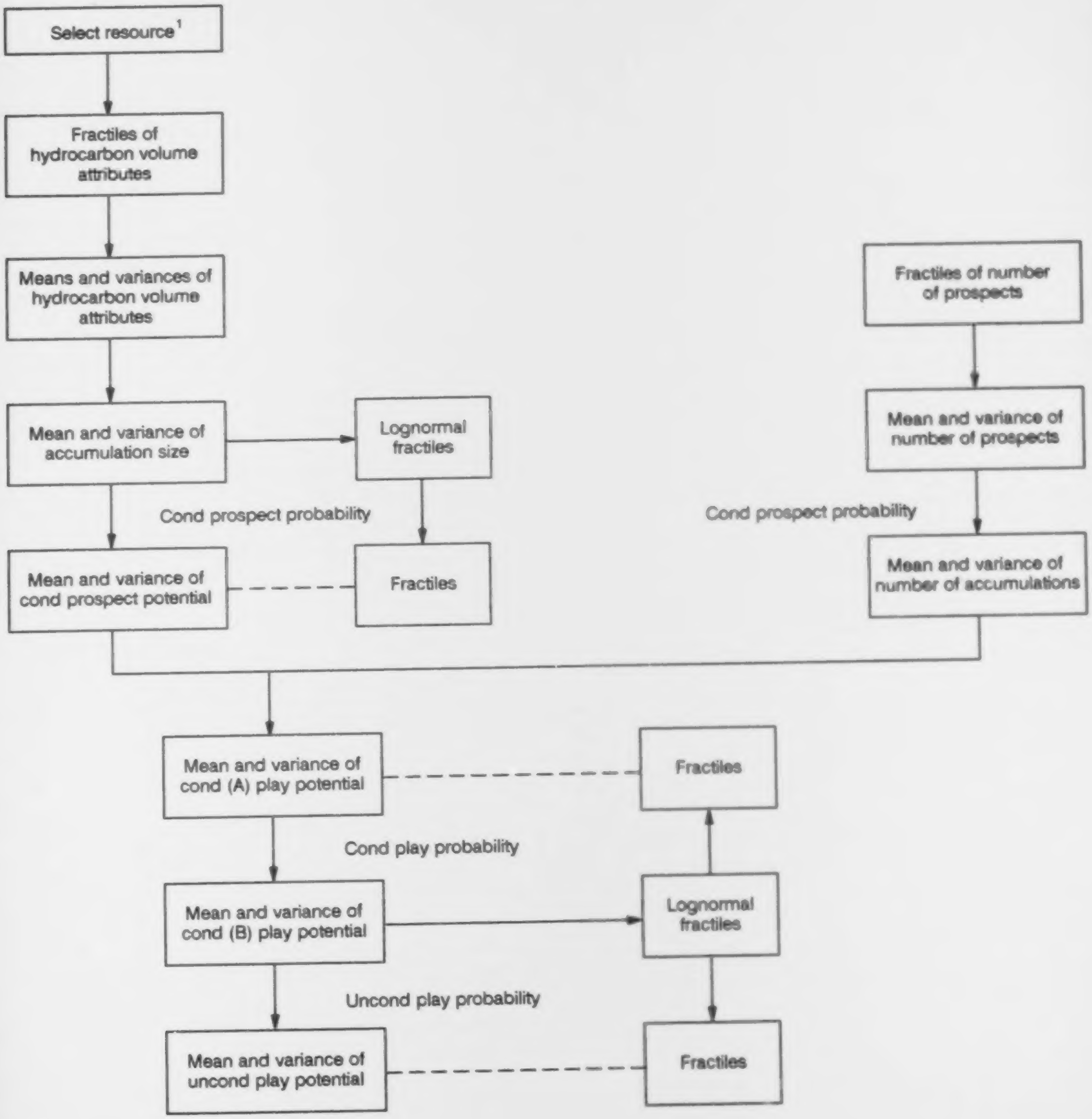
[9] For additional information about RASP and FASP see Bird, "A Comparison of the Play Analysis Technique..."; Hansen and Kornbrath, "Resource Appraisal Simulation for Petroleum..."; and L.P. White, "A Play Approach to Hydrocarbon Resource Assessment and Evaluation," in Oil and Gas Assessment – Methods and Applications, AAPG Studies in Geology #21, Dudley D. Rice ed. (Tulsa, OK: American Association of Petroleum Geologists, 1986), pp. 125-132.

[10] R.A. Crovelli, "A Comparison of Analytic and Simulation Methods for Petroleum Play Analysis and Aggregation," U.S. Geological Survey Open-File Report 86-97, 1986.

[11] L.W. Cooke, "Estimates of Undiscovered, Economically Recoverable Oil and Gas Resources for the Outer Continental Shelf As Of July 1984." U.S. Department of the Interior, Minerals Management Service, 1985, p. 9.

Figure B-2.—Flow Chart of Analytic Method of Play Analysis


Select resource[1]
Fractiles of hydrocarbon volume attributes
Means and variances of hydrocarbon volume attributes
Mean and variance of accumulation size
Lognormal fractiles
Cond prospect probability
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Fractiles
Fractiles of number of prospects
Mean and variance of number of prospects
Cond prospect probability
Mean and variance of number of accumulations
Mean and variance of cond (A) play potential
Fractiles
Cond play probability
Mean and variance of cond (B) play potential
Lognormal fractiles
Uncond play probability
Mean and variance of uncond play potential
Fractiles

[1] Oil, nonassociated gas, dissolved gas, and gas resources are each assessed in turn.

SOURCE: Robert A. Crovelli, "A Comparison of Analytic and Simulation Methods for Petroleum Play Analysis and Aggregation." U.S. Geological Survey Open-File Report 86-97 1986.

Using risk factors and Monte Carlo simulation, PRESTO simulates an exploratory drilling program. For each PRESTO trial, every prospect in the basin is "drilled," and discovered resources are summed to determine an area total. The simulation is repeated as many as 5000 times, and results are sorted, ranked, and divided into percentiles. Output includes the conditional 95 percent, 5 percent, and mean resource estimates for oil and gas and the corresponding probability of economically recoverable hydrocarbons after accounting for the possibility that there may be no hydrocarbons in the area (the "risked" estimates).

The major difference between RASP and PRESTO is that PRESTO incorporates economic factors into the model. Thus, not only does PRESTO determine the amount of resources in each prospect, it determines whether the resources within each prospect are large enough to warrant development. To accomplish this, PRESTO uses a single point estimate of the minimum economic field size (MEFS) required for development in the area. The MEFS is derived from MONTCAR, a discounted cash flow analysis program. An important consideration in determining MEFS is the assumed price of oil—as the price of oil decreases, the MEFS increases. Other important considerations include development and operating costs, and distance from markets.

Significantly, the prospect's resources are added to the total for the area only if the MEFS is exceeded for the prospect being "drilled." But if the MEFS is not exceeded, the prospect's resources are set to zero. Hence, PRESTO estimates of undiscovered, economically recoverable resources may be conservative. For example, a prospect that, in isolation, is not estimated to contain enough resources to be developed may nevertheless be developed if there are other prospects in the area that are large enough to develop, or even if a number of fields, all below the MEFS, are found in close proximity and can share infrastructure costs. The Lisburne, Endicott, and Milne Point fields, for instance, would never have been developed were it not for their proximity to Prudhoe Bay and the TAPS pipeline. PRESTO would have modeled these fields as having zero resources, but they are currently contributing to TAPS throughput, if only about 5 to 10 percent. Likewise, some geologists believe that PRESTO estimates of economically recoverable resources in ANWR are conservative.[12] The MEFS for ANWR as a whole has been determined to be about 440 million barrels (for a $33 per barrel price of North Slope oil in 2000 (1984 dollars)) .[13] However, given the possibility of shared infrastructure costs, recent declining development costs, the high probability that more prospects than were evaluated in DOI's ANWR analysis will subsequently be identified, and other factors, the estimate of economically recoverable resources do appear too conservative.[14]

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[12] For example, Joe Riva of the Congressional Research Service.

[13] U.S. Department of the Interior, Arctic National Wildlife Refuge, Alaska, Coastal Plain Resource Assessment, April 1987, p. 79.

[14] Energy Information Administration, Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge (Revised Edition), EIA Service Report, October 1987, pp. 15-17.

Appendix C
Glossary

API gravity: The standard American Petroleum Institute method for specifying the density of crude petroleum. The density in degrees of API equals (141.5°P)-131.5, where P is the specific gravity of the oil measured at 60° F.

barrel: A common unit of measurement of liquids in the petroleum industry; it equals 42 U.S. standard gallons.

chemical flooding: An enhanced oil recovery technique based upon adding various chemicals to the water used in waterflooding in order to increase waterflood efficiencies.

conditional mean resources: The average amount of oil and/or gas expected to exist if at least one of the prospects in an area contained economically recoverable accumulations of hydrocarbons and if all of the prospects modelled were drilled.

directional drilling: Drilling that has been deliberately angled away from the vertical.

drilling mud: A special mixture of clay, water, or oil and chemical additives pumped through the drill pipe and drill bit. The mud cools the rapidly rotating bit; lubricates the drill pipe as it turns in the well bore; carries rock cuttings to the surface; serves as a plaster to prevent the wall of the bore hole from crumbling or collapsing; and provides the weight or hydrostatic head to prevent formation fluids from entering the well bore and to control downhole pressures.

economically recoverable resource estimate: An assessment of the hydrocarbon potential of a field that takes into account physical and technological constraints on production and the relation of costs and market price.

enhanced oil recovery: See tertiary recovery.

fault: A fracture along which the rocks on one side are displaced relatively to those on the other.

field: Composed of a single pool or multiple pools that are grouped on or related to a single structural and/or stratigraphic feature. "Pool" is a term meaning a body of reservoir rock containing recoverable oil and/or gas.

formation: A rock mass composed of individual beds or units with similar physical characteristics or origin.

gas lift: The effect of either naturally or artificially induced gas pressure in an oil well that causes the oil to flow from the well.

gas/oil ratio: The proportion of gas produced relative to oil produced from a reservoir(s) or field(s), usually expressed as cubic feet per barrel of oil.

gas injection: The process of injecting (or reinjecting) gas into a reservoir to maintain the producing pressure.

infill drilling: Drilling at a smaller spacing than called for in the original development plan, designed to speed up production and/or increase ultimate recovery.

in-place resources: The total amount of oil in a field, only a portion of which will ultimately be recoverable.

inferred, potential reserves: Those resources that should eventually be added to proved reserves through extensions of known fields, revisions of earlier reserves estimates resulting from new subsurface and production information, and production from new producing zones in known fields.

log, well log: Measurements of the physical properties of the drilled section, generally taken while raising measurement devices up the wellbore on an electrical cable.

marginal probability: The probability that economically recoverable oil and gas resources exist in an area under study.

migration: The movement of oil, gas, or water through porous and permeable rock.

miscible flooding: A technique based upon using some gas – such as enriched reservoir gas or CO_2 – to miscibly displace some oils, thereby permitting the recovery of most of the in-place oil contacted.

outer continental shelf: The part of the continental shelf beyond the line that marks State ownership; that part of the offshore area under Federal jurisdiction.

pay: A rock stratum or zone that yields oil or gas.

permafrost: Any soil, subsoil, or other surficial deposit occurring in arctic, subarctic, and alpine regions at a variable depth beneath the Earth's surface in which a temperature below freezing has existed continuously for a long time.

permeability: The degree to which a rock will allow liquid or gas to pass through it.

play: A rock formation or group of formations within a sedimentary basin with geological characteristics similar to those that have been proven productive. A play serves as a planning unit around which an exploration program can be constructed.

pool: A subsurface accumulation of oil and/or gas in porous and permeable rock, having its own isolated pressure system. Theoretically, a single well could drain a pool. Also known as a reservoir.

porosity: The proportion of a rock's total volume occupied by the voids between the mineral grains.

pressure cycling: A technique of injecting natural gas or CO_2 into a producing formation and alternating high and low pressures to induce mixing with the crude and thus stimulating the flow.

primary recovery: The fraction of original oil and/or gas in-place that will flow unaided or can be pumped from the reservoir rock matrix to the surface.

production: Activities that take place after the successful establishment of means for the removal of oil and/or gas, including such removal, field operations, operation monitoring, maintenance, and workover drilling.

proprietary information: Scientific, engineering, and financial data, information, and derivatives thereof that are not released to the public for a specified term. Federal laws, regulations, statutes, or contractual requirements affect the terms.

prospect: An area that is a potential site of economically recoverable petroleum accumulation based on preliminary exploration. A play is composed of one or more prospects.

recoverable oil: The sum of proved and potential reserves. May also include estimated undiscovered recoverable oil.

reserves, proved reserves (oil): The portion of an oil field's resource base that has been identified by drilling and estimated directly by engineering measurements, and that is recoverable at current prices and technology.

reservoir pressure: The pressure existing at the level of the oil and/or gas productive zone in a well.

reservoir rock: A porous and permeable rock, e.g., sandstone or limestone, which contains oil and/or gas that can be produced.

resources: The total amount of oil or gas that remains to be produced in the future. Generally does not include oil or gas in such small deposits or under such difficult conditions that it is not expected to be produced at any foreseeable price/technology combination.

risked mean resources: The product obtained by multiplying the conditional mean value by the marginal probability that economically recoverable hydrocarbon resources exist in the area under study.

secondary recovery: Oil and gas obtained by the augmentation of reservoir energy, often by the injection of gas or water into a producing reservoir.

show: An indication of the presence of oil or gas in the formations penetrated during drilling.

shut-in: Shutoff, so there is no flow; refers to a well, plant, pump, etc., when valves are closed. A shut-in well can be returned to production, often with some downhole cleanup work.

source rock: Sedimentary rock in which organic material under pressure, heat, and time was transformed to liquid or gaseous hydrocarbons. Source rock is usually shale or limestone.

stratigraphic trap: A trap for oil and/or gas, resulting from changes in rock type, porosity, or permeability, that occurs as a result of sedimentation and diagenetic processes rather than from structural deformation.

structural trap: A trap for oil or gas resulting from folding, faulting, or other rock deformation.

tertiary recovery: Oil recovered using advanced techniques beyond secondary recovery techniques. Techniques include injection of steam or of other injected substances, such as rich miscible gas, carbon dioxide, polymers, solvents, surfactants, micellar fluids, or even microorganisms.

thermal recovery/stimulation: A petroleum recovery process that utilizes heat (in the form of steam or hot gas) to thin viscous oil in an underground reservoir and allow it to flow more readily toward wells through which it can be brought to the surface.

trap: Any barrier to the upward movement of oil or gas that allows either or both to accumulate. A trap includes reservoir rock and overlying impermeable cap rock.

viscosity: That property of a fluid which determines its rate of flow. As the temperature of a fluid is increased, its viscosity decreases, and it therefore flows more readily.

waterflood: A secondary-recovery operation for oilfields in which water is injected into a petroleum reservoir to force more oil to the producing wells.

work-over: A term applied to any remedial operation performed on a well after completion.

undiscovered, economically recoverable resources: Quantities of economically recoverable oil and gas estimated to exist outside known fields.

undiscovered, in-place resources: Quantities of oil and gas estimated to exist outside known fields, without reference to technological or economic factors.

wellhead: The equipment used to maintain surface control of a well. It is formed of the casing head, tubing head, and Christmas tree (assemblage of valves, gages, fittings, etc.). Also refers to various parameters as they exist at the wellhead: wellhead pressure, wellhead price of oil, etc.

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